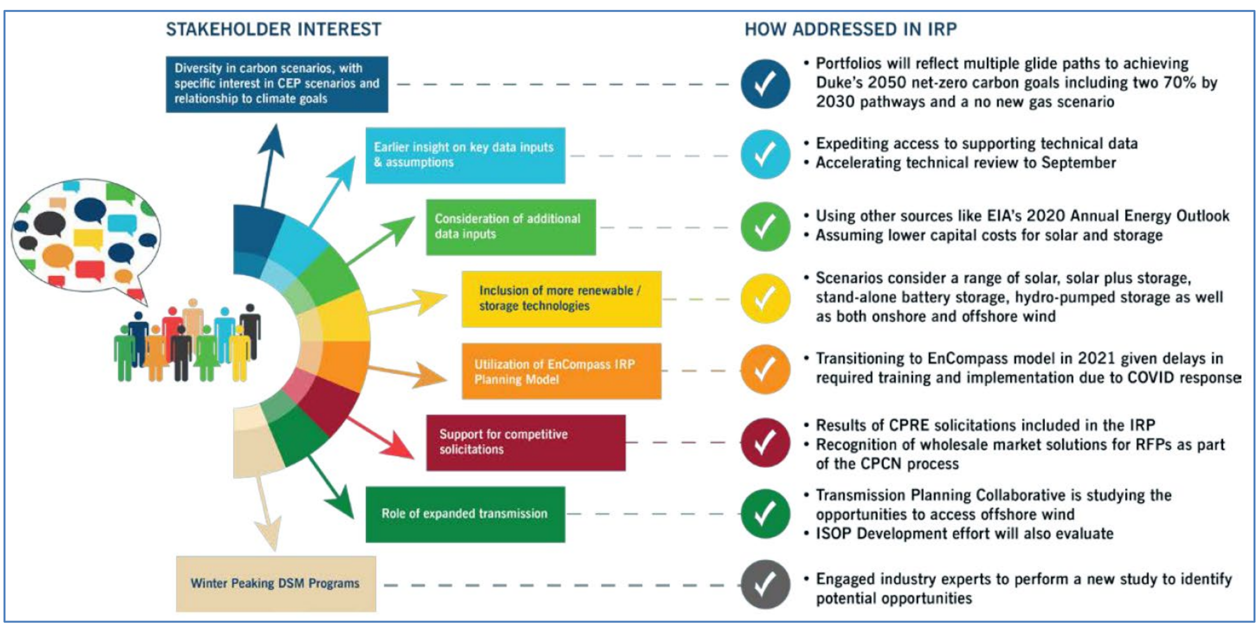
Stakeholder Portal and Available Tools

The Companies developed a stakeholder engagement process for the 2020 IRP process. This process involved engaging stakeholders throughout the IRP development process to allow for open dialogue between the Companies and interested stakeholders. The intent was to keep stakeholders informed and involved throughout the process and to solicit ideas, concerns and suggestions as the IRP is being developed. The consultant, ICF, was retained to mediate and oversee the stakeholder process.

The process began with an "IRP 101" webinar and was followed with two stakeholder forums in March and April of 2020. The first forum provided ICF's overview of national resource planning trends, as well as detailed discussions of four topics of greatest interest identified by stakeholders. The second forum involved a more detailed discussion of topics of greatest interest as identified by stakeholders.

The two forums were followed up by a third meeting to discuss how the Companies incorporated stakeholder input into the IRP in June 2020. The figure below, included on page 11 of the IRPs, shows the various input stakeholders had throughout the process and how the input was incorporated into the development of the IRP.



Finally, a technical briefing was held in mid-September 2020 to discuss technical details of the development of the IRP and detailed assumptions and results.

To ensure information from all webinars and forums was available to stakeholders at all times, the Companies developed an IRP and stakeholder reference portal. The portal is available on the Duke Energy site at IRP Reference Information Portal (duke-energy.com). A snapshot of the home page is included below.

DUKE ENERGY. Carolinas Integrated Resource Planning (IRP) MENU

Source: Adapted from ICF

IRP Stakeholder Engagement Approach

In the first quarter of 2020, Duke Energy initiated a process to engage stakeholders in North Carolina and South Carolina on our integrated resource planning efforts in both states. By engaging with stakeholders prior to the IRP filings, the company has an opportunity to listen and understand what is important to individual stakeholders, address their questions and determine how their feedback could potentially inform the IRP process within the 2020 requirements established under rule R8-60 in North Carolina and Act 62 in South Carolina.

To facilitate engagement, Duke Energy has contracted with ICF, who has also been helping with the company's Integrated System Operations and Planning (ISOP) stakeholder engagement efforts. ICF's engagement will ensure consideration of lessons learned and best practices from similar efforts across the industry. Duke Energy kicked off the IRP engagement process with targeted stakeholder listening sessions in February and March, followed by an IRP 101 virtual meeting facilitated by ICF on March 10. Duke Energy also worked with ICF to provide two IRP Forum engagement sessions for NC and SC stakeholders on March 17 and April 16, with a final follow up session with stakeholders on June 18, respectively. Topics addressed during these sessions included in both forums reflected those areas of greatest interest from stakeholders based on intervenor comments, listening sessions and pre and post-Forum surveys distributed by ICF.

The section containing access to all materials from each webinar/forum is provided below.

IRP Engagement Materials

Provided below are the associated materials from the two IRP Forums and one pre-filing Webinar that Duke Energy held with North Carolina and South Carolina stakeholders in 2020. ICF, which facilitated these forums, has provided a summary report for all of Duke Energy's IRP engagement activities leading up to and through the June 18 Webinar.

IRP 101, March 10, 2020

Co-led by ICF and Duke Energy, this webinar provides foundational information about the integrated resource planning process, including what it is, why it is relevant, national trends as well as Duke Energy's approach to the process and current and regulatory requirements.

- IRP Webinar 101 Slides
- Webinar Recording

IRP Forum #1: March 17, 2020

This forum covered ICF's overview of national trends in IRP, Duke Energy's approach towards IRP, and breakout sessions on four main topics that stakeholders had identified as those of greatest interest: resource planning, carbon reduction, energy efficiency/demand response and load forecasting.

- Agenda
- Forum Slides
- Forum Recordings
  - IRP Overview
  - Resource Evaluation
  - Carbon Reduction in the IRP
  - Energy Efficiency/Demand Response
  - Load Forecasting
  - Q&A from March 17 session

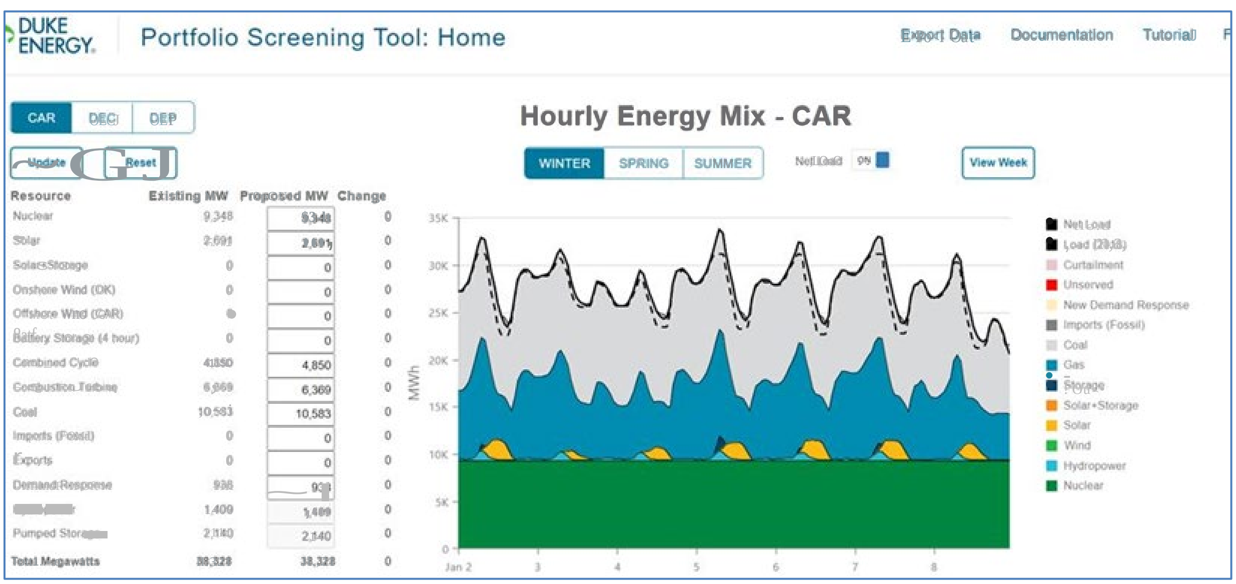
IRP Forum #2: April 16, 2020

This forum took a deeper dive on topics identified by stakeholders as most important to them. The three focus areas included: resource planning, carbon reduction, energy efficiency/demand response.

- Agenda
- Forum Slides
- Q&A from April 16 session

Additionally, once filed, the IRP documents and all attached studies have been made available on this portal as seen below.

Duke Energy is also the first Company in the nation to have developed a Portfolio Screening Tool made available for use by the stakeholders. The tool allows the user to illustratively see how portfolios of various resource types meet the energy demand over a 7-day winter, spring or summer period in DEC and DEP's service territory. A snapshot of the tool capability is shown below.



The tool is available online at all times at PST (duke-energy.com).

Summary of Discovery

The bullet points below summarize the extensive discovery process the Companies undertook in an effort to be responsive and transparent throughout the 2020 IRP discovery process. The information below captures the magnitude of the requests and the Companies' efforts to openly share data with stakeholders in the process. While this list reflects many of the topics the responded to, it does not reflect all the information provided or the hours of time and parties involved throughout the Companies to respond to these requests and provide forthright and thoughtful responses.

2020 IRP Discovery Summary

- 16 individual intervenors
- All intervenors requested ALL other discovery (except NCWARN who refused to sign an NDA)
- Intervenors had access to NC and SC discovery and responses
- Intervenor access to FTP site for Resource Adequacy Study and IRP
    - Approximately 350 MB of information provided
        - Study Reports
        - SERVM inputs, outputs, calculations and other supporting files
        - Resource Adequacy Study Stakeholder documents
        - IRP input data
- Responded and/or provided access to approximately 3,200 data requests,[1] including, but not limited to, the following:
    - All SO/PROSYM model inputs (provided on FTP site)
        - Requested additional model runs
        - Requested model documentation/license agreement
    - Hourly SO/PROSYM input/output files
        - Including System Lambdas
        - Including Marginal Costs
    - Resource Adequacy Study
        - All study inputs/outputs
        - Detailed modeling methodologies
        - Detailed assumptions and justification
        - Supporting workpapers
    - Market Potential Study
        - Study inputs
        - Assumptions and justification
        - Modeling methodologies

[1] Carolina Clean Energy Business Association ("CCEBA") issued a data request for all answers and documents provided in the current IRP Proceeding before the North Carolina Utilities Commission. Responses to those data requests are included in the 3,200 count.

  - Study outputs
- Capacity Value of Storage Study
  - Inputs/outputs
  - Detailed modeling methodologies
  - Detailed assumptions and justification
- Coal Retirement Study
  - Detailed explanation of process
  - Input/output files
  - Justification for process
- Capital Cost Model
  - Detail on variables/inputs
  - Load forecast
  - Historical peaks
  - Top ten peaks of past year for both winter and summer
  - Analysis of recent historical and weather normalized peaks
  - Detailed information, including sales, for each customer class
  - Detailed information behind each table provided in IRP document
  - Hourly and monthly load information (historical and projected)
  - Weather Normal Calculations and Methodologies
  - Model information – equations, statistics, variables, inputs, etc.
  - Usage Per Customer – historical and forecast
- Transmission
  - Justification for all new transmission projects
  - Transmission assumptions and details for each portfolio
  - Transmission
- Generic Unit Summary
  - Inputs
  - Assumptions
  - Justification
  - Data sources
  - Busbar curves and data used to create
- Natural Gas Prices
  - Provide values used
  - Natural gas market prices & justification for using
  - Historical natural gas consumption
- Renewables
  - Contribution to peak justification for solar, storage, solar + storage
  - Detailed information behind renewables projections
  - Justifications on projections
  - CPRE/CPRE Tranche 2

    - Offshore wind policy
    - Interconnection constraint justification
- EE/DSM
    - Program costs broken down into categories
    - Winter demand response
- Purchase Power Contracts
    - Detailed contracts for each
- Presentations/Reports
    - All stakeholder process presentations
    - Board of Director presentations/minutes
    - Presentations to senior management
    - Credit reports for Duke Energy Corp.
- IRP Document
    - Differences between DEC and DEP document
    - Load, Capacity and Reserves table files with inputs/formulas, etc.
    - Source data for tables/graphs presented in IRP
    - Detail on first need calculation for DEC and DEP
- Customer Bill Impacts
    - All files used to calculate bill impacts
    - Assumptions for calculation
- Joint Dispatch Agreement
    - Copy of agreement between DEC/DEP
- ISOP
    - Details of progress
- Energy Storage
    - Assumptions in IRP
    - Assumptions on Solar + Storage
- Plants online at time of peak
    - Unit names
    - Loadings
    - Outage information
    - Etc.

Duke Energy Carolinas, LLC's
and
Duke Energy Progress, LLC's
Response to
SC Office of Regulatory Staff
Data Request No. 3-1

Docket No. 2019-224-E
Docket No. 2019-225-E

Date of Request: **November 9, 2020**
Date of Response: **November 20, 2020**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Glen A. Snider, Director IRP & Analytics, and was provided to the SC Office of Regulatory Staff under my supervision.

Rebecca J. Dulin
Associate General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

3-1 On page 6 of DEC's IRP, it states, "In accordance with North Carolina and South Carolina regulatory requirements, the 2020 IRP includes a most economic or "least-cost" portfolio, as well as multiple scenarios reflecting a range of potential future resource portfolios."

a. Please confirm that the Company believes that the Base Case without Carbon policy is the plan it was referring to when it stated, "the 2020 IRP includes a most economic or "least-cost" portfolio." If that was not the plan, please identify the plan the Company was referring to.

b. Recognizing that the South Carolina regulatory requirement intends for the proposed resource plan to be "the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed," explain how the Company's plan meets the criteria of being the most reasonable plan at the time the plan is reviewed.

c. Recognizing that the South Carolina regulatory requirement intends for the proposed resource plan to be "the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed," explain how the Company's plan meets the criteria of being the most prudent plan at the time the plan is reviewed.

d. Please confirm that the Company intends to use the Base without Carbon Policy portfolio for its avoided cost proceeding or to perform other evaluations such as value of solar calculations, cost-effectiveness, DSM evaluations, etc. in South Carolina.

e. In the event that the Commission in South Carolina orders the Company to modify its IRP pursuant to S.C. Code Ann § 58-37-40(C)(3) and it is different than the approved plan in North Carolina, what implications would there be for having different IRPs in each state? In answering this, please contextualize the Company's statement on page 5 of the DEC IRP, wherein it states, "The IRP to be filed in each state is identical in form and content. It is important to note that DEC cannot fulfill two different IRPs for one system.

Response:

a. The Base Case without Carbon policy portfolio is the least cost plan in an environment where there is no future carbon policy. The Base Case with Carbon policy portfolio is the least cost plan under a future where carbon policy is instituted as assumed in the IRPs. While there exists uncertainty in the timing and level of future carbon policy the Companies felt it would be reasonable and prudent to identify base case "least cost" portfolios under both a no carbon policy future and a with carbon policy future.

b. As mentioned in subpart (a) to this question, the IRPs, as filed, include two base case least cost portfolios under both a no carbon policy future and a portfolio assuming a carbon policy future. In addition, the IRPs show four additional portfolios that achieve more aggressive carbon reduction targets that may be realized in the future, recognizing the potential for both technological advancements and the potential for regional or federal policy directives addressing clean energy goals.

The two base portfolios along with the four additional portfolios including the scenario and sensitivity analysis presented in the IRPs are fully consistent with Act 62, section (7)(B)(e) which requires the Companies to present "*several* [emphasis added] resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations". Accordingly, the Companies believe that the IRPs, inclusive of the six portfolios, present a reasonable range of options which constitute—in its entirety—a plan consistent with the tenets of Act 62 and represent the most prudent plan at the time the plan is being reviewed.

c. Please see response to subpart (b) of this question.

d. In keeping with historic practice, at this time the Companies intend to use the Base without Carbon Policy for the purposes described in the question. Should policy initiatives addressing carbon come to fruition, the Companies would alter their approach to incorporate such future policy as appropriate.

e. While the Companies believe that their plans as filed are fully consistent with both the intent and letter of Act 62 and as such gives the Commission no reason to modify its IRPs, the Companies also recognize the authority and latitude of the Commission in rendering its decision in this matter. Should the Commission order a change to the base case in the IRPs that is not consistent with the North Carolina IRPs, it could result in systemic differences in valuations in other dockets. The Companies' affirmation of sub-part (b) to this question, which asked-

> "Please confirm that the Company intends to use the Base without Carbon Policy portfolio for its avoided cost proceeding or to perform other evaluations such as value of solar calculations, cost-effectiveness, DSM evaluations, etc. in South Carolina",

illustrates that any mandated inconsistency in the Base without Carbon Policy portfolio would, by extension, result in valuation differences for NC and SC in the aforementioned proceedings.

Moreover, NC and SC regulatory bodies have long treated resource planning in a consistent manner, implicitly recognizing the inherent benefits of the large geography and resource diversity enabled by generation in one state serves customers in another, even when faced with policy variations between the states regarding renewable energy (e.g., NC Senate Bill 3 (2007), SC Act 236 (2014), NC House Bill 589 (2017), and SC Act 62 (2019).

To the extent that the utility commissions require different resource plans with different requirements to satisfy such plans, such requirements raise concerns about shared costs and benefits and may ultimately lead to cost shifting from one state to another, or even – if taken to a logical conclusion—a less optimal mix of resources that could ultimately cost customers more.

TABLE N-1
CROSS REFERENCE - NC R8-60 REQUIREMENTS

REQUIREMENT	REFERENCE	LOCATION
15-year Forecast of Load, Capacity and Reserves	NC R8-60 (c) 1	Chapter 3 Appendix C
Comprehensive analysis of all resource options	NC R8-60 (c) 2	Chapter 8 Chapter 12 Appendix A Appendix G
Assessment of Purchased Power	NC R8-60 (d)	Chapter 12 Appendix A Appendix J Attachment II
Assessment of Alternative Supply-Side Energy Resources	NC R8-60 (e)	Chapter 8 Appendix G
Assessment of Demand-Side Management	NC R8-60 (f)	Chapter 4 Appendix D Attachment V
Evaluation of Resource Options	NC R8-60 (g)	Chapter 5 Chapter 8 Appendix A Appendix D Appendix G
Short-Term Action Plan	NC R8-60 (h) 3	Chapter 14
REPS Compliance Plan	NC R8-60 (h) 4	Attachment I
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources * 10-year History of Customers and Energy Sales * 15-year Forecast w & w/o Energy Efficiency * Description of Supply-Side Resources	NC R8-60 (i) 1(i) NC R8-60 (i) 1(ii) NC R8-60 (i) 1(iii)	Chapter 3 Chapter 4 Appendix C Appendix D Attachment V

TABLE N-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS (CONT.)

REQUIREMENT	REFERENCE	LOCATION
Generating Facilities * Existing Generation * Planned Generation * Non-Utility Generation	NC R8-60 (i) 2(i) NC R8-60 (i) 2(ii) NC R8-60 (i) 2(iii)	Chapter 2 Chapter 12 Appendix B Appendix J
Reserve Margins	NC R8-60 (i) 3	Chapter 9 Chapter 12 Attachment III
Wholesale Contracts for the Purchase and Sale of Power * Wholesale Purchased Power Contracts * Request for Proposal * Wholesale Power Sales Contracts	NC R8-60 (i) 4(i) NC R8-60 (i) 4(ii) NC R8-60 (i) 4(iii)	Chapter 12 Chapter 14 Appendix A Appendix J
Transmission Facilities	NC R8-60 (i) 5	Chapter 7 Appendix L
Energy Efficiency and Demand-Side Management * Existing Programs * Future Programs * Rejected Programs * Consumer Education Programs	NC R8-60 (i) 6(i) NC R8-60 (i) 6(ii) NC R8-60 (i) 4(iii) NC R8-60 (i) 4(iv)	Chapter 4 Appendix D Attachment V
Assessment of Alternative Supply-Side Energy Resources * Current and Future Alternative Supply-Side Resources * Rejected Alternative Supply-Side Resources	NC R8-60 (i) 7(i) NC R8-60 (i) 7(ii)	Chapter 8 Appendix A Appendix G
Evaluation of Resource Options (Quantitative Analysis)	NC R8-60 (i) 8	Appendix A
Levelized Bus-bar Costs	NC R8-60 (i) 9	Appendix G
Smart Grid Impacts	NC R8-60 (i) 10	Appendix D
Legislative and Regulatory Issues		Appendix I
Greenhouse Gas Reduction Compliance Plan		Chapter 16 Appendix A
Other Information (Economic Development)		Appendix M
NCUC Subsequent Orders		Table N-3

TABLE N-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each electrical utility must submit its integrated resource plan to the commission. The integrated resource plan must be posted on the electrical utility's website and on the commission's website.	Part (C)(2)	Post - filing
a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Part (C)(2)	Chapter 3 Appendix A Appendix C
The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Part (C)(2)	Chapter 8 Appendix A Appendix F Appendix G
projected energy purchased or produced by the utility from a renewable energy resource;	Part (C)(2)	Chapter 5 Chapter 12 Appendix A Appendix E Appendix J Appendix N (DEP)
a summary of the electrical transmission investments planned by the utility;	Part (C)(2)	Chapter 7 Appendix A Appendix L

TABLE N-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i)customer energy efficiency and demand response programs; (ii)facility retirement assumptions; and (iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Part (C)(2)	Chapter 3 Chapter 4 Chapter 12 Appendix A Appendix B Appendix C Appendix D Appendix I
data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Part (C)(2)	Chapter 2 Appendix B
plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan	Part (C)(2)	Chapter 7 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A

TABLE N-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs	Part (C)(2)	Chapter 7 Chapter 8 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A Appendix G
a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Part (C)(2)	Chapter 3 Chapter 4 Appendix C Appendix D
An integrated resource plan may include distribution resource plans or integrated system operation plans.	Part (C)(2)	Chapter 7 Chapter 11 Chapter 15 Appendix A Appendix L

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The two Base Case Plans (i.e. Base CO2 Future and Base No CO2 Future) … encourages the Companies to carry forward both alternatives for their next IRPs due for 2020.”	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 12 Appendix A
DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company's existing coal-fired generating units are retired by the earliest practicable date. The "earliest practicable date" shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified. In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A Appendix I

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Commission expects that the "earliest practicable date" chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 7 Chapter 11 Appendix A Appendix L
The Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20 E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION

Updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	IRP Filing Letters Chapter 9 Attachment III
In documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission will direct DEC and DEP to more fully explain and detail the study results.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The updated Resource Adequacy Study should provide additional clarity around outputs… At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR).	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Executive Summary Chapter 15
The 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 15
The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 13
Demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 3 Chapter 4 Chapter 8 Chapter 12 Appendix A Appendix D Appendix G Appendix J

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 12 Chapter 14 Appendix A Appendix J
A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans."	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Chapter 12 Chapter 16 Appendix A
(d) A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Appendix A Appendix D

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Include information, analyses, and modeling regarding economic retirement of coal-fired units	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Model continued operation under least cost principles in competition with alternative new resources	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
If continued operation until fully depreciated is least cost alternative, shall separately model an alternative scenario premised on advanced retirement of one or more of such units (including an analysis of the difference in cost from the base case and preferred case scenarios.)	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Chapter 9 Attachment III
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Filed Under Seal
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7	Appendix D

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Appendix D Attachment V
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Chapter 3 Appendix C

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 14 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14	Chapter 5 Appendix E Appendix K
Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 10

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Duke will include Li-ion battery storage technology in the economic supply-side screening process as part of the IRP.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 19) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 6 Chapter 8 Chapter 12 Appendix A Appendix G Appendix H
DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.	E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	Appendix D

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	Chapter 8 Appendix A Appendix F Appendix G
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Chapter 5 Appendix A Appendix E Appendix N (DEP)
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret.	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Attachment I

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program.	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program)	Appendix D
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Chapter 14 Appendix D

TABLE O-1
CROSS REFERENCE - NC R8-60 REQUIREMENTS

REQUIREMENT	REFERENCE	LOCATION
15-year Forecast of Load, Capacity and Reserves	NC R8-60 (c) 1	Chapter 3 Appendix C
Comprehensive analysis of all resource options	NC R8-60 (c) 2	Chapter 8 Chapter 12 Appendix A Appendix G
Assessment of Purchased Power	NC R8-60 (d)	Chapter 12 Appendix A Appendix J Attachment II
Assessment of Alternative Supply-Side Energy Resources	NC R8-60 (e)	Chapter 8 Appendix G
Assessment of Demand-Side Management	NC R8-60 (f)	Chapter 4 Appendix D Attachment V
Evaluation of Resource Options	NC R8-60 (g)	Chapter 5 Chapter 8 Appendix A Appendix D Appendix G
Short-Term Action Plan	NC R8-60 (h) 3	Chapter 14
REPS Compliance Plan	NC R8-60 (h) 4	Attachment I
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources * 10-year History of Customers and Energy Sales * 15-year Forecast w & w/o Energy Efficiency * Description of Supply-Side Resources	NC R8-60 (i) 1(i) NC R8-60 (i) 1(ii) NC R8-60 (i) 1(iii)	Chapter 3 Chapter 4 Appendix C Appendix D Attachment V

TABLE O-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS (CONT.)

REQUIREMENT	REFERENCE	LOCATION
Generating Facilities * Existing Generation * Planned Generation * Non-Utility Generation	NC R8-60 (i) 2(i) NC R8-60 (i) 2(ii) NC R8-60 (i) 2(iii)	Chapter 2 Chapter 12 Appendix B Appendix J
Reserve Margins	NC R8-60 (i) 3	Chapter 9 Chapter 12 Attachment III
Wholesale Contracts for the Purchase and Sale of Power * Wholesale Purchased Power Contracts * Request for Proposal * Wholesale Power Sales Contracts	NC R8-60 (i) 4(i) NC R8-60 (i) 4(ii) NC R8-60 (i) 4(iii)	Chapter 12 Chapter 14 Appendix A Appendix J
Transmission Facilities	NC R8-60 (i) 5	Chapter 7 Appendix L
Energy Efficiency and Demand-Side Management * Existing Programs * Future Programs * Rejected Programs * Consumer Education Programs	NC R8-60 (i) 6(i) NC R8-60 (i) 6(ii) NC R8-60 (i) 4(iii) NC R8-60 (i) 4(iv)	Chapter 4 Appendix D Attachment V
Assessment of Alternative Supply-Side Energy Resources * Current and Future Alternative Supply-Side Resources * Rejected Alternative Supply-Side Resources	NC R8-60 (i) 7(i) NC R8-60 (i) 7(ii)	Chapter 8 Appendix A Appendix G
Evaluation of Resource Options (Quantitative Analysis)	NC R8-60 (i) 8	Appendix A
Levelized Bus-bar Costs	NC R8-60 (i) 9	Appendix G
Smart Grid Impacts	NC R8-60 (i) 10	Appendix D
Legislative and Regulatory Issues		Appendix I
Greenhouse Gas Reduction Compliance Plan		Chapter 16 Appendix A
Other Information (Economic Development)		Appendix M
NCUC Subsequent Orders		Table O-3

TABLE O-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each electrical utility must submit its integrated resource plan to the commission. The integrated resource plan must be posted on the electrical utility's website and on the commission's website.	Part (C)(2)	Post - filing
a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Part (C)(2)	Chapter 3 Appendix A Appendix C
The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Part (C)(2)	Chapter 8 Appendix A Appendix F Appendix G
projected energy purchased or produced by the utility from a renewable energy resource;	Part (C)(2)	Chapter 5 Chapter 12 Appendix A Appendix E Appendix J Appendix N (DEP)
a summary of the electrical transmission investments planned by the utility;	Part (C)(2)	Chapter 7 Appendix A Appendix L

TABLE O-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i)customer energy efficiency and demand response programs; (ii)facility retirement assumptions; and (iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Part (C)(2)	Chapter 3 Chapter 4 Chapter 12 Appendix A Appendix B Appendix C Appendix D Appendix I
data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Part (C)(2)	Chapter 2 Appendix B
plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan	Part (C)(2)	Chapter 7 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A

TABLE O-2

CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs	Part (C)(2)	Chapter 7 Chapter 8 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A Appendix G
a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Part (C)(2)	Chapter 3 Chapter 4 Appendix C Appendix D
An integrated resource plan may include distribution resource plans or integrated system operation plans.	Part (C)(2)	Chapter 7 Chapter 11 Chapter 15 Appendix A Appendix L

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The two Base Case Plans (i.e. Base CO_2 Future and Base No CO_2 Future) … encourages the Companies to carry forward both alternatives for their next IRPs due for 2020.”	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 12 Appendix A
DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company's existing coal-fired generating units are retired by the earliest practicable date. The "earliest practicable date" shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified. In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A Appendix I

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Commission expects that the "earliest practicable date" chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 7 Chapter 11 Appendix A Appendix L
The Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20 E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	IRP Filing Letters Chapter 9 Attachment III
In documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission will direct DEC and DEP to more fully explain and detail the study results.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The updated Resource Adequacy Study should provide additional clarity around outputs... At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR).	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Executive Summary Chapter 15
The 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 15
The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 13
Demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 3 Chapter 4 Chapter 8 Chapter 12 Appendix A Appendix D Appendix G Appendix J

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 12 Chapter 14 Appendix A Appendix J
A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans."	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Chapter 12 Chapter 16 Appendix A
A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Appendix A Appendix D

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Include information, analyses, and modeling regarding economic retirement of coal-fired units	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Model continued operation under least cost principles in competition with alternative new resources	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
If continued operation until fully depreciated is least cost alternative, shall separately model an alternative scenario premised on advanced retirement of one or more of such units (including an analysis of the difference in cost from the base case and preferred case scenarios.)	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Chapter 9 Attachment III
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Filed Under Seal
Future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 6 E-100, Sub 1118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Chapter 3 Appendix C
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7	Appendix D

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Appendix D Attachment V
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Chapter 3 Appendix C

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

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Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 10

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DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.	E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	Appendix D

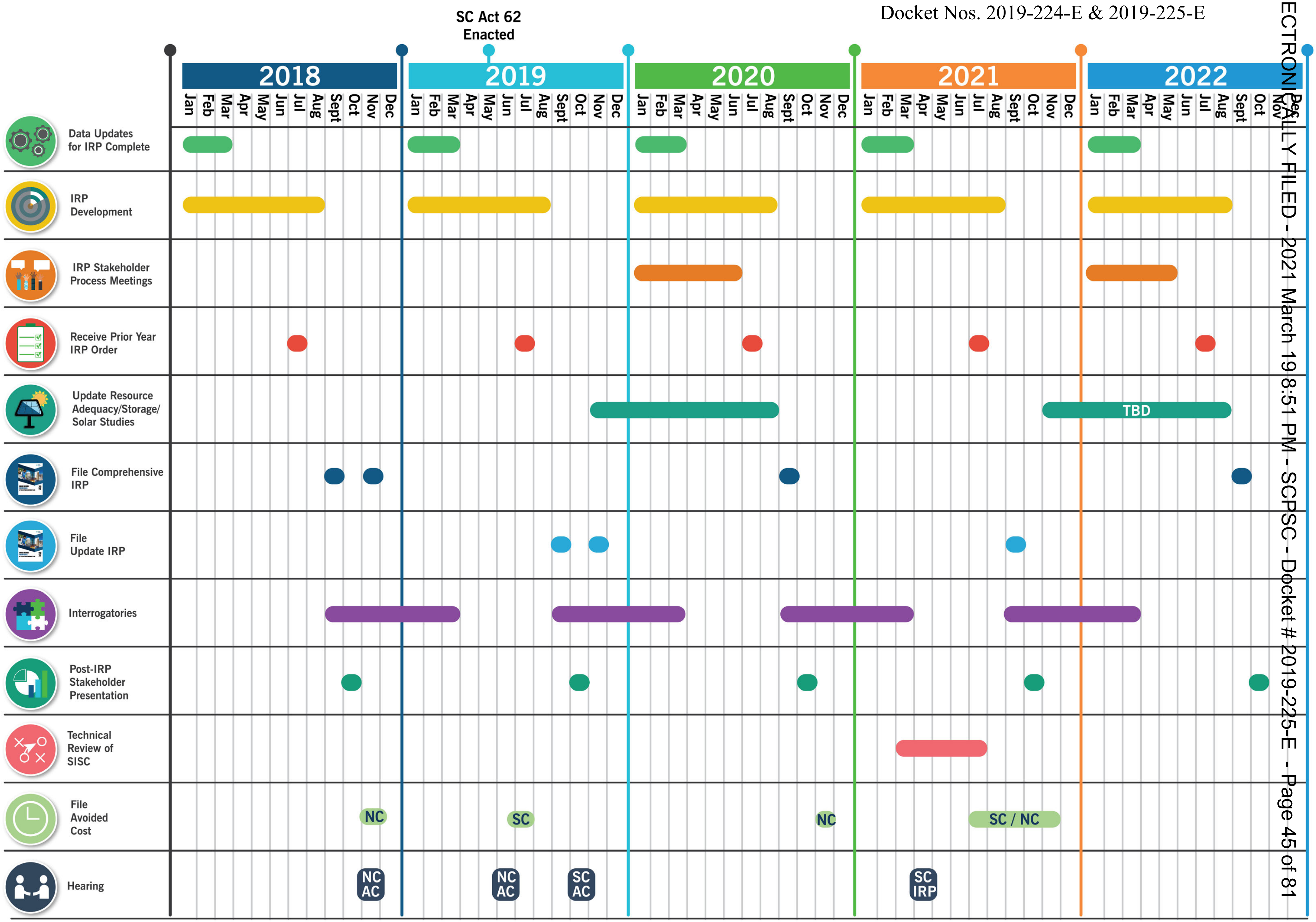
TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	Chapter 8 Appendix A Appendix F Appendix G
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Chapter 5 Appendix A Appendix E Appendix N (DEP)
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret.	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Attachment I

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program.	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program)	Appendix D
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Chapter 14 Appendix D


SC Act 62
Enacted
2018
2019
2020
2021
2022
Jan Feb Mar Apr May Jun Jul Aug Sept Oct Nov Dec
Data Updates for IRP Complete
IRP Development
IRP Stakeholder Process Meetings
Receive Prior Year IRP Order
Update Resource Adequacy/Storage/ Solar Studies
TBD
File Comprehensive IRP
File Update IRP
Interrogatories
Post-IRP Stakeholder Presentation
Technical Review of SISC
File Avoided Cost
NC
SC
NC
SC / NC
Hearing
NC AC
NC AC
SC AC
SC IRP

Snider Exhibit 6-PROSYM/LCR CROSS REFERENCE TABLE

DEC Capacity (Winter MW)

NOTES: PROSYM uses December convention and LCR uses January (some capacities may be off a year)

Solar is input into PROSYM monthly with load profiles as opposed to an annual value. Additionally, the way data is received for each is grouped very differently.

A comparison like this will not result in the same solar totals, but the end results are the same in PROSYM and LCR.

LCR Reference to LCRs provided in discovery response

PROSYM Station Name	PROSYM Unit Type	DEC LCR Tab	DEC LCR Row/Section	Notes	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1	COAL-DEC	Existing Capacity	Column C		167	167	167	0	0	0	0	0	0	0	0	0	0	0	0
Allen 2	COAL-DEC	Existing Capacity	Column C		167	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Allen 3	COAL-DEC	Existing Capacity	Column C		270	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Allen 4	COAL-DEC	Existing Capacity	Column C		267	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Allen 5	COAL-DEC	Existing Capacity	Column C		259	259	259	0	0	0	0	0	0	0	0	0	0	0	0
Contract 6	Purc-Firm-DEC	Purchases_Contracts	Row 29		4	4	4	4	4	4	4	4	4	4	4	0	0	0	0
Bad Creek	Pumped Stor-DEC	Existing Capacity/ Cap Additions	Column G/ 'Other Additions' Rows 57-60	2021 in Existing Capacity/ Remaining in Cap Additions	1,425	1,490	1,555	1,620	1,620	1,620	1,620	1,620	1,620	1,620	1,620	1,620	1,620	1,620	1,620
Belews Creek 1	COAL-DEC	Existing Capacity	Column C		1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110
Belews Creek 2	COAL-DEC	Existing Capacity	Column C		1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110
Biomass NUG DEC	NUG-DEC	Renewable Cap Totals - Winter	Rows 89-103		27	8	8	8	2	2	2	2	2	2	2	2	0	0	0
Biomass REN DEC	Renewable-DEC	Renewable Cap Totals - Winter	Rows 89-103		50	45	45	45	42	42	39	39	36	28	11	2	0	0	0
Buck CC 2x1	CC-DEC	Existing Capacity	Column G	Combined Buck CC total in	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Buck CC DF	CC-DEC	Existing Capacity	Column G	LCR	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Car Onshore Wind DEC	Renewable-DEC	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Catawba 1	Nuclear-DEC	Existing Capacity	Column G		1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Catawba 2	Nuclear-DEC	Existing Capacity	Column G		1,180	1,186	1,186	1,186	1,186	1,186	1,186	1,186	1,186	1,186	1,186	1,186	1,186	1,186	1,186
Contract 1	Purc-Firm-DEC	Purchases_Contracts	Row 24		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clemson CHP	CHP-DEC	LCR(W)	Row 42		16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Cliffside 5	COAL-DEC	Existing Capacity	Column C		546	546	546	546	546	0	0	0	0	0	0	0	0	0	0
Cliffside 6	COAL-DEC	Existing Capacity	Column C		849	849	849	849	849	849	849	849	849	849	849	849	849	849	849
Cowans Ford Hydro	Hydro-DEC	Existing Capacity	Column G		324	324	324	324	324	324	324	324	324	324	324	324	324	324	324
Contract 2	Purc-Firm-DEC	Purchases_Contracts	Row 25		1	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Contract 3	Purc-Firm-DEC	Purchases_Contracts	Row 26		2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract 4	Purc-Firm-DEC	Purchases_Contracts	Row 27		2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dan River CC 2x1	CC-DEC	Existing Capacity	Column G	Combined Dan River CC	598	598	598	598	598	598	598	598	598	598	598	598	598	598	598
Dan River CC DF	CC-DEC	Existing Capacity	-	total in LCR	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
DEC 4hr Battery 1	Pumped Stor-DEC	LCR(W)	Row 42		6	28	56	83	111	139	167	167	167	167	167	167	167	167	167
DEC 4hr Battery 2	Pumped Stor-DEC	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC 6hr Battery 1	Pumped Stor-DEC	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC 6hr Battery 2	Pumped Stor-DEC	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 1 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,093
DEC CCG2 1 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	131
DEC CCG2 10 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 10 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 11 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 11 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 12 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 12 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 13 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 13 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 14 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 14 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 15 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 15 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 2 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 2 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 3 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 3 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 4 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 4 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 5 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 5 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Snider Exhibit 6-PROSYM/LCR CROSS REFERENCE TABLE

DEC Capacity (Winter MW)

NOTES: PROSYM uses December convention and LCR uses January (some capacities may be off a year)

Solar is input into PROSYM monthly with load profiles as opposed to an annual value. Additionally, the way data is received for each is grouped very differently.

A comparison like this will not result in the same solar totals, but the end results are the same in PROSYM and LCR.

LCR Reference to LCRs provided in discovery response

PROSYM Station Name	PROSYM Unit Type	DEC LCR Tab	DEC LCR Row/Section	Notes	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
DEC CCG2 6 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 6 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 7 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 7 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 8 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 8 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 9 2x1	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CCG2 9 DF	Future CC-DEC	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CHP 1	CHP-DEC	LCR(W)	Row 42		0	27	54	54	54	54	54	54	54	54	54	54	54	54	54
DEC CTF MB 1	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	457	457	457	457	457	457
DEC CTF MB 10	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 11	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 12	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 13	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 14	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 15	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 16	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 17	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 18	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 2	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	457	457	457	457	457
DEC CTF MB 3	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	913
DEC CTF MB 4	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 5	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 6	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 7	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 8	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC CTF MB 9	Future CT-DEC	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC Interstate Pipe	CC-DEC	N/A	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEC NCEMC Sale SO	Purc-Firm-DEC	N/A	N/A		10	10	10	10	10	10	10	0	0	0	0	0	0	0	0
DEC Nuclear SMR	Future Nuc-DEC	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM DEC EWH	DSM-DEC	EE_DSM	Row 25		2	3	3	4	4	4	4	4	4	4	4	4	4	4	4
DSM DEC ISSG	DSM-DEC	EE_DSM	Row 22		100	95	90	86	82	78	78	78	78	78	78	78	78	78	78
DSM DEC IVVC	DSM-DEC	EE_DSM	Row 52		0	0	17	34	173	174	176	177	179	180	182	184	185	187	189
DSM DEC PM	DSM-DEC	EE_DSM	Row 21		0	4	6	9	13	19	28	40	56	77	101	128	154	179	199
DSM DEC PS	DSM-DEC	EE_DSM	Rows 23 and 24		347	337	340	343	345	345	345	345	345	345	345	345	345	345	345
DSM DEC WS IS	DSM-DEC	EE_DSM	Rows 33 - 35 and 39 - 41		24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
DSM DEC WS PM	DSM-DEC	EE_DSM	Rows 43 - 45		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM DEC WS PS	DSM-DEC	EE_DSM	Rows 36 - 38		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Fut Purc 1	Purc-Firm-DEC	N/A	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Solar+Storage DEC	Renewable-DEC	Renewables	Row 43		0	0	20	49	79	98	222	346	469	542	614	611	608	605	602
Future Solar+Storage DEC 2	Renewable-DEC	LCR(W)	Row 33		0	0	0	0	0	0	0	0	75	150	225	375	525	675	825
Hydro NUG DEC	NUG-DEC	Renewable Cap Totals - Winter	Rows 89-103		9	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Hydro REN DEC	Renewable-DEC	Renewable Cap Totals - Winter	Rows 89-103		33	27	27	5	5	5	1	1	1	1	0	0	0	0	0
Jocassee	Pumped Stor-DEC	Existing Capacity	Column G		780	780	780	780	780	780	780	780	780	780	780	780	780	780	780
Keowee Hydro	Hydro-DEC	Existing Capacity	Column G		152	152	152	152	152	152	152	152	152	152	152	152	152	152	152
Lee NCEMC Sale 1	CC Sale-DEC	Existing Capacity	Column G		-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38
Lee NCEMC Sale 2	CC Sale-DEC	Existing Capacity	Column G	Already net out in LCR existing capacity	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31
Lee NCEMC Sale 3	CC Sale-DEC	Existing Capacity	Column G		-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31
Lee SC 3 NG	COAL-DEC	Existing Capacity	Column C		173	173	173	173	173	173	173	173	173	173	0	0	0	0	0
Lee SC CC 1 2x1	CC-DEC	Existing Capacity	Column G	LCR only includes this value	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
Lee SC CC 1 DF	CC-DEC	Existing Capacity	Column G	LCR does not account for the 100 MW owned by NCEMC	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Lee SC CT	CT-DEC	Existing Capacity	Column K		96	96	96	96	96	96	96	96	96	96	96	96	96	96	96

Snider Exhibit 6-PROSYM/LCR CROSS REFERENCE TABLE

DEC Capacity (Winter MW)

NOTES: PROSYM uses December convention and LCR uses January (some capacities may be off a year)

Solar is input into PROSYM monthly with load profiles as opposed to an annual value. Additionally, the way data is received for each is grouped very differently.

A comparison like this will not result in the same solar totals, but the end results are the same in PROSYM and LCR.

LCR Reference to LCRs provided in discovery response

PROSYM Station Name	PROSYM Unit Type	DEC LCR Tab	DEC LCR Row/Section	Notes	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Lincoln CT 17	Future CT-DEC	Cap Additions	'Other Additions' Rows 57-60		369	382	402	402	402	402	402	402	402	402	402	402	402	402	402
Lincoln CT 1-8	CT-DEC	Existing Capacity	Column K		784	784	784	784	784	784	784	784	784	784	784	784	784	784	784
Lincoln CT 9-16	CT-DEC	Existing Capacity	Column K		781	781	781	781	781	781	781	781	781	781	781	781	781	781	781
Lower Catawba Hydro	Hydro-DEC	Existing Capacity	Column G		368	368	368	368	368	368	368	368	368	368	368	368	368	368	368
Marshall 1	COAL-DEC	Existing Capacity	Column C		380	380	380	380	380	380	380	380	380	380	380	380	380	380	0
Marshall 2	COAL-DEC	Existing Capacity	Column C		380	380	380	380	380	380	380	380	380	380	380	380	380	380	0
Marshall 3	COAL-DEC	Existing Capacity	Column C		658	658	658	658	658	658	658	658	658	658	658	658	658	658	0
Marshall 4	COAL-DEC	Existing Capacity	Column C		660	660	660	660	660	660	660	660	660	660	660	660	660	660	0
McGuire 1	Nuclear-DEC	Existing Capacity	Column G		1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199
McGuire 2	Nuclear-DEC	Existing Capacity	Column G		1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187
MillCreek CT	CT-DEC	Existing Capacity	Column K		751	751	751	751	751	751	751	751	751	751	751	751	751	751	751
Misc ROR Hydro	Hydro-DEC	Existing Capacity	Column G		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Contract 7	Purc-Firm-DEC	Purchases_Contracts	Row 31		162	158	160	161	163	164	166	165	129	130	0	0	0	0	0
Nantahala Hydro	Hydro-DEC	Existing Capacity	Column K		103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
NCEMC Primary Sale	Nuclear Sale-DEC	Existing Capacity	Row 5	Net out of total (PROSYM has multiple lines ; only one chosen at a time)	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481
NCEMC Primary Sale Backst	Nuclear Sale-DEC	Existing Capacity	Row 6		-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481	-481
NCEMC Secondary Sale	Nuclear Sale-DEC	LCR(W)	Row 12		-103	-103	-103	-103	-103	-103	-103	-103	-103	-103	-103	-103	-103	-103	-103
NCMPA Sale 1	Nuclear Sale-DEC	Existing Capacity	Row 5	Net out of total (PROSYM has multiple lines ; only one chosen at a time)	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208
NCMPA Sale 2	Nuclear Sale-DEC	Existing Capacity	Row 5		-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208
NCMPA Sale 3	Nuclear Sale-DEC	Existing Capacity	Row 5		-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208
NCMPA Sale 4	Nuclear Sale-DEC	Existing Capacity	Row 5		-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208
Oconee 1	Nuclear-DEC	Existing Capacity	Column G		865	865	880	880	880	880	880	880	880	880	880	880	880	880	880
Oconee 2	Nuclear-DEC	Existing Capacity	Column G		872	887	887	887	887	887	887	887	887	887	887	887	887	887	887
Oconee 3	Nuclear-DEC	Existing Capacity	Column G		881	881	896	896	896	896	896	896	896	896	896	896	896	896	896
Onshore Wind DEC	Renewable-DEC	Renewable Cap Totals - Winter	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onshore Wind DEC 2	Renewable-DEC	LCR(W)	Row 34		0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
PMPA Backst 1	Sale-Firm-DEC	Existing Capacity	Row 5	Net out of total (PROSYM has multiple lines ; only one chosen at a time)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMPA Backst 2	Sale-Firm-DEC	Existing Capacity	Row 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMPA Backst 3	Sale-Firm-DEC	Existing Capacity	Row 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMPA Backst 4	Sale-Firm-DEC	Existing Capacity	Row 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMPA Sale 1	Nuclear Sale-DEC	Existing Capacity	Row 5		-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69
PMPA Sale 1 NonContingent	Nuclear Sale-DEC	Existing Capacity	Row 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMPA Sale 2	Nuclear Sale-DEC	Existing Capacity	Row 5		-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69
PMPA Sale 2 NonContingent	Nuclear Sale-DEC	Existing Capacity	Row 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMPA Sale 3	Nuclear Sale-DEC	Existing Capacity	Row 5		-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69
PMPA Sale 3 NonContingent	Nuclear Sale-DEC	Existing Capacity	Row 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMPA Sale 4	Nuclear Sale-DEC	Existing Capacity	Row 5		-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69	-69
PMPA Sale 4 NonContingent	Nuclear Sale-DEC	Existing Capacity	Row 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockingham CT	CT-DEC	Existing Capacity	Column K		895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
Contract 5	Purc-SEPA-DEC	Purchases_Contracts	Row 28		8	8	8	8	8	8	8	8	8	8	8	0	0	0	0
CPRE Solar+Storage DEC	Renewable-DEC	Renewable Cap Totals - Winter	Row 60	These will not match because data is input differently in PROSYM vs. LCR	0	115	114	114	113	113	112	111	111	110	110	109	109	108	108
Solar 3rd Party Curt DEC	Renewable-DEC	Renewable Cap Totals - Winter	Row 60		188	225	354	352	350	348	347	345	343	341	340	407	405	403	401
Solar 3rd Party NonCurt DEC	Renewable-DEC	Renewable Cap Totals - Winter	Row 60		625	664	672	713	749	785	781	777	773	769	765	692	689	685	682
Solar HB589 & Future DEC	Renewable-DEC	Renewable Cap Totals - Winter	Row 60		95	429	637	789	973	1,115	1,236	1,356	1,475	1,544	1,611	1,604	1,597	1,590	1,584
Solar Util Owned DEC	Renewable-DEC	Renewable Cap Totals - Winter	Row 60		83	98	122	121	121	120	119	119	118	118	117	116	116	115	115
Solar HB589 & Future DEC 2	Renewable-DEC	LCR(W)	Row 33		0	0	0	0	75	150	225	300	375	450	525	675	825	975	1,125
Und Other DEC	NUG-DEC	Renewable Cap Totals - Winter	Row 32		10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Catawba Hydro	Hydro-DEC	Existing Capacity	Column G		133	133	133	133	133	133	133	133	133	133	133	133	133	133	133

Snider Exhibit 6-PROSYM/LCR CROSS REFERENCE TABLE

DEP Capacity (Winter MW)

Purchase Contracts CONFIDENTIAL

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A comparison like this will not result in the same solar totals, but the end results are the same in PROSYM and LCR.

LCR Reference to LCRs provided in discovery response

PROSYM Station Name	PROSYM Unit Type	DEP LCR Tab	DEP LCR Row/Section	Notes	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Asheville CC 1x1	CC-DEP	Existing Capacity	Row G		560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
Asheville CT 3	CT-DEP	Existing Capacity	Row K		185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
Asheville CT 4	CT-DEP	Existing Capacity	Row K		185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
Biomass NUG DEP	NUG-DEP	Renewable Cap Totals _Winter	Row 91 and 99		59	53	52	52	51	51	51	1	1	1	1	1	1	1	1
Biomass REN DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 96		76	75	72	72	62	62	62	57	40	40	40	40	40	40	40
Blewett CT 1	CT-DEP	Existing Capacity	Row K		68	68	68	68	68	0	0	0	0	0	0	0	0	0	0
Blewett Hydro	Hydro-DEP	Existing Capacity	Row C		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Contract 4	Purc-Firm-DEP	Purchases_Contracts	Row 27	Sums to Contract #4	165	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract 4	Purc-Firm-DEP	Purchases_Contracts	Row 27		162	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract 4	Purc-Firm-DEP	Purchases_Contracts	Row 27		162	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract 4	Purc-Firm-DEP	Purchases_Contracts	Row 27		191	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract 4	Purc-Firm-DEP	Purchases_Contracts	Row 27		191	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract 4	Purc-Firm-DEP	Purchases_Contracts	Row 27		0	850	850	850	850	850	850	0	0	0	0	0	0	0	0
Brunswick 1	Nuclear-DEP	Existing Capacity	Row G		975	975	975	975	979	979	979	979	979	979	979	979	979	979	979
Brunswick 2	Nuclear-DEP	Existing Capacity	Row G		953	953	953	953	953	953	953	959	959	969	969	969	969	969	969
Contract 1	Purc-Firm-DEP	Purchases_Contracts	Row 24	Sums to Contract #1	0	0	0	0	260	260	260	260	260	260	260	260	260	260	260
Contract 1	Purc-Firm-DEP	Purchases_Contracts	Row 24		260	260	260	260	0	0	0	0	0	0	0	0	0	0	0
Car Onshore Wind DEP	Renewable-DEP	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract 8	Purc-Firm-DEP	Purchases_Contracts	Row 31	Contract #8	195	195	195	195	195	195	0	0	0	0	0	0	0	0	0
CPRE Solar+Storage DEP	Renewable-DEP	Renewable Cap Totals _Winter	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTLM Sut 1	CT-DEP	Existing Capacity	Row K		49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
CTLM Sut 2	CT-DEP	Existing Capacity	Row K		49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Darl CT 1	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Darl CT 10	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Darl CT 12	CT-DEP	Existing Capacity	Row K		133	133	133	133	133	133	133	133	133	133	133	133	133	133	133
Darl CT 13	CT-DEP	Existing Capacity	Row K		133	133	133	133	133	133	133	133	133	133	133	133	133	133	133
Darl CT 2	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Darl CT 3	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Darl CT 4	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Darl CT 6	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Darl CT 7	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Darl CT 8	CT-DEP	Existing Capacity	Row K		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP 4hr Battery 1	Pumped Stor-DEP	LCR(W)	Row 42 and Row 34	Put into model and LCR differently	32	47	66	85	106	127	148	148	148	148	629	629	629	629	800
DEP 4hr Battery 2	Pumped Stor-DEP	LCR(W)	Row 34		0	0	0	0	0	0	0	0	0	0	0	0	0	0	369
DEP 4hr Battery 3	Pumped Stor-DEP	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP Asheville CPCN CT	Future CT-DEP	Cap Additions	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 1 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	1,093	1,093	1,093	1,093	1,093	1,093	1,093	1,093
DEP CCG2 1 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	131	131	131	131	131	131	131	131
DEP CCG2 10 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 10 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 11 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 11 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 12 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 12 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 13 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 13 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 2 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	1,093	1,093	1,093	1,093	1,093	1,093	1,093
DEP CCG2 2 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	131	131	131	131	131	131	131
DEP CCG2 3 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 3 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 4 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 4 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 5 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 5 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 6 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 6 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 7 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 7 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 8 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Snider Exhibit 6-PROSYM/LCR CROSS REFERENCE TABLE
DEP Capacity (Winter MW)

Purchase Contracts CONFIDENTIAL

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LCR Reference to LCRs provided in discovery response

PROSYM Station Name	PROSYM Unit Type	DEP LCR Tab	DEP LCR Row/Section	Notes	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
DEP CCG2 8 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 9 2x1	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CCG2 9 DF	Future CC-DEP	LCR(W)	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CHP 1	CHP-DEP	LCR(W)	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 1	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	457	913	913	1,826	1,826	1,826	1,826	1,826	1,826	1,826
DEP CTF MB 10	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 11	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 12	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 13	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 14	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 2	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 3	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 4	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 5	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 6	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 7	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 8	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP CTF MB 9	Future CT-DEP	LCR(W)	Row 31		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP Interstate Pipe	CC-DEP	N/A	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEP Nuclear SMR	Future Nuc-DEC	LCR(W)	Row 29		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM DEP DRA	DSM-DEP	EE_DSM	Row 23		15	17	20	22	24	24	24	24	24	24	24	24	24	24	24
DSM DEP DSDR	DSM-DEP	EE_DSM	Row 26		186	186	188	189	96	97	98	99	100	100	101	102	103	104	105
DSM DEP EWB	DSM-DEP	EE_DSM	Row 25		1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
DSM DEP EWH	DSM-DEP	EE_DSM	Row 22		2	8	12	15	18	23	31	41	54	71	91	112	134	154	171
DSM DEP LLC	DSM-DEP	EE_DSM	Row 24		255	258	260	263	266	268	268	268	268	268	268	268	268	268	268
DSM DEP West DRA	DSM-DEP	EE_DSM	Row 23		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DSM DEP West DSDR	DSM-DEP	EE_DSM	Row 26		30	29	30	30	0	0	0	0	0	0	0	0	0	0	0
DSM DEP West EWH	DSM-DEP	EE_DSM	Row 22		18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Contract 7	NUG-DEP	Purchases_Contracts	Row 30	Contract #7	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0
Contract 6	NUG-DEP	Purchases_Contracts	Row 29	Contract #6	11	11	11	11	11	11	11	11	11	11	11	11	0	0	0
Fut Purc 2	Purc-Firm-DEP	N/A	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Solar+Storage DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 58		0	0	0	14	13	13	88	163	237	286	334	333	331	329	328
Future Solar+Storage DEP 2	Renewable-DEP	LCR(W)	Row 32		0	0	0	0	0	0	0	0	0	150	300	525	750	975	1,200
Undesignated PPAs	Purc-Firm-DEP	Purchases_Contracts	Row 36	Sums to Undesignated PPAs	0	0	0	0	0	0	0	850	850	850	850	850	850	850	850
Undesignated PPAs	Purc-Firm-DEP	Purchases_Contracts	Row 36		0	0	0	0	0	0	195	195	195	195	195	195	195	195	195
Undesignated PPAs	Purc-Firm-DEP	Purchases_Contracts	Row 36		0	0	0	0	0	0	0	0	0	0	0	0	375	375	375
Undesignated PPAs	Purc-Firm-DEP	Purchases_Contracts	Row 36		0	0	0	0	168	168	168	168	168	168	168	168	168	168	168
Undesignated PPAs	Purc-Firm-DEP	Purchases_Contracts	Row 36		0	0	0	0	0	0	0	0	165	165	165	165	165	165	165
Undesignated PPAs	Purc-Firm-DEP	Purchases_Contracts	Row 36		0	0	0	0	0	0	178	178	178	178	178	178	178	178	178
Undesignated PPAs	Purc-Firm-DEP	Purchases_Contracts	Row 36		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harris 1	Nuclear-DEP	Existing Capacity	Row G		1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Hydro NUG DEP	NUG-DEP	Renewable Cap Totals _Winter	Row 90		10	6	6	6	6	5	3	2	1	1	0	0	0	0	0
Hydro REN DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 95		1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Lee CC 1 3x1	CC-DEP	Existing Capacity	Row G		990	990	990	990	990	990	990	990	990	990	990	990	990	990	990
Lee CC 1 DF	CC-DEP	Existing Capacity	Row G		69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
Marshall Hydro	Hydro-DEP	Existing Capacity	Row C		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Mayo 1	COAL-DEP	Existing Capacity	Row C		746	746	746	746	746	746	746	746	0	0	0	0	0	0	0
Contract 10	Purc-Firm-DEP	Purchases_Contracts	Row 33	Contract #10	129	129	129	129	129	129	129	129	129	129	129	129	0	0	0
NCEMC 150MW Sale	Sale-Firm-DEP	LCR(W)	Row 11		0	-150	-150	0	0	0	0	0	0	0	0	0	0	0	0
Contract 2	Purc-Firm-DEP	Purchases_Contracts	Row 25	Contract #2	375	375	375	375	375	375	375	375	375	375	375	375	0	0	0
Contract 3	Purc-Firm-DEP	Purchases_Contracts	Row 26	Contract #3	168	168	168	168	0	0	0	0	0	0	0	0	0	0	0
Onshore Wind DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 30		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onshore Wind DEP 2	Renewable-DEP	LCR(W)	Row 33		0	0	0	0	0	0	0	0	0	0	0	0	150	300	450
Contract 5	Purc-Firm-DEP	Purchases_Contracts	Row 28	Contract #5	403	268	252	234	221	168	171	165	0	0	0	0	0	0	0
Rich CC 4 2x1	CC-DEP	Existing Capacity	Row G		570	570	570	570	570	570	570	570	570	570	570	570	570	570	570
Rich CC 5 2x1	CC-DEP	Existing Capacity	Row G		589	589	589	589	589	589	589	589	589	589	589	589	589	589	589
Rich CC 5 DF	CC-DEP	Existing Capacity	Row G		61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
Rich CC 5 PAG	CC-DEP	Existing Capacity	Row G		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Richmond CT 1	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197

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DEP Capacity (Winter MW)

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PROSYM Station Name	PROSYM Unit Type	DEP LCR Tab	DEP LCR Row/Section	Notes	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Richmond CT 2	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197
Richmond CT 3	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197
Richmond CT 4	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197
Richmond CT 6	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197
Robinson 2	Nuclear-DEP	Existing Capacity	Row G		793	793	793	793	793	793	793	793	793	793	793	793	793	793	793
Contract 9	Purc-Firm-DEP	Purchases_Contracts	Row 32	Contract #9	178	178	178	178	178	178	0	0	0	0	0	0	0	0	0
Roxboro 1	COAL-DEP	Existing Capacity	Row C		380	380	380	380	380	380	380	380	0	0	0	0	0	0	0
Roxboro 2	COAL-DEP	Existing Capacity	Row C		673	673	673	673	673	673	673	673	0	0	0	0	0	0	0
Roxboro 3	COAL-DEP	Existing Capacity	Row C		698	698	698	698	698	698	698	0	0	0	0	0	0	0	0
Roxboro 4	COAL-DEP	Existing Capacity	Row C		711	711	711	711	711	711	711	0	0	0	0	0	0	0	0
Solar 3rd Party Curt DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 57	These will not match because data is input differently in PROSYM vs. LCR	971	1,110	1,434	1,427	1,500	1,642	1,633	1,625	1,617	1,609	1,601	1,593	1,585	1,577	1,569
Solar 3rd Party NonCurt DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 57		1,752	1,773	1,770	1,826	1,881	1,936	1,926	1,916	1,906	1,896	1,887	1,877	1,867	1,858	1,849
Solar 3rd Party NonCurt DEP West	Renewable-DEP	Renewable Cap Totals _Winter	Row 57		27	27	27	27	27	27	27	27	28	28	28	28	28	28	28
Solar Util Owned DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 57		137	164	164	163	162	161	160	160	159	158	157	156	156	155	154
Solar HB589 & Future DEP	Renewable-DEP	Renewable Cap Totals _Winter	Row 57		7	88	90	198	279	360	435	509	582	630	678	675	673	671	668
Solar HB589 & Future DEP 2	Renewable-DEP	N/A	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sut CC 1 2x1	CC-DEP	Existing Capacity	Row G		658	658	658	658	658	658	658	658	658	658	658	658	658	658	658
Sut CC 1 DF	CC-DEP	Existing Capacity	Row G		61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
Sutton CT 1	CT-DEP	Existing Capacity	N/A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tillery Hydro	Hydro-DEP	Existing Capacity	Row C		84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
Walters Hydro	Hydro-DEP	Existing Capacity	Row C		112	112	112	112	112	112	112	112	112	112	112	112	112	112	112
Wayne CT 1	CT-DEP	Existing Capacity	Row K		192	192	192	192	192	192	192	192	192	192	192	192	192	192	192
Wayne CT 2	CT-DEP	Existing Capacity	Row K		192	192	192	192	192	192	192	192	192	192	192	192	192	192	192
Wayne CT 3	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197
Wayne CT 4	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197
Wayne CT 5	CT-DEP	Existing Capacity	Row K		197	197	197	197	197	197	197	197	197	197	197	197	197	197	197
Weatherspn CT 1	CT-DEP	Existing Capacity	Row K		164	164	164	164	164	0	0	0	0	0	0	0	0	0	0

ORS Recommendation No. 11:

ORS recommends the Companies supply additional information regarding their relicensing plans (including a timeline) for the Oconee and Robinson nuclear units and their plans to conduct economic evaluations to assess the benefits of relicensing the units. ORS also recommends the Companies provide additional insight into why it is beginning the relicensing process so far in advance of the relicensing dates, and why Robinson unit 2 is relicensing after Oconee. ORS recommends this information be provided in a modified IRP in this proceeding.

Response:

The Companies view their nuclear fleet as viable and necessary resources to provide reliable, cost-effective, clean energy to South Carolina customers in the future. As such, the Companies intend to pursue subsequent license renewal ("SLR") of all existing nuclear facilities, beginning with a submittal for Oconee Nuclear Station in 2021. An SLR application for each nuclear plant will follow, approximately three years from the previous SLR application submittal. A team of highly skilled and experienced employees, including nuclear engineers, scientists, environmental experts, regulatory specialists and more, is supporting SLR application work across the fleet. Updates to the SLR schedule will be provide in future IRPs.

The Companies first presented plans for SLR of their nuclear units in the 2019 IRP. Prior to the filing of the 2019 IRP, the Companies performed analysis to determine the cost-effectiveness of SLR for each of their nuclear stations. SLR was found to save customers billions of dollars as compared to retirement of the nuclear facilities. This information was provided in discovery in the 2019 IRP.

The nuclear units' license expirations begin in 2030. Federal regulations stipulate that if an SLR application is filed at least five (5) years in advance of license expiration, then the existing license will not be deemed to have expired until the application has been finally determined. This is commonly referred to as the "timely renewal" rule and provides protection that allows continued operation if the NRC review and approval is delayed beyond license expiration.

Units at the Robinson Nuclear Plant, Oconee Nuclear Station and Brunswick Nuclear Plant have licenses that expire before 2034—Robinson Nuclear Plant in 2030, Oconee Nuclear Station in 2033 and Brunswick Nuclear Plant in 2034—meaning that all three SLR applications for these plants should be filed before 2029 (five years in advance of license expiration) to meet the timely renewal rule. An SLR application takes approximately three (3) years to prepare and two (2) years for NRC to review. Given these time constraints, the Companies have not begun the SLR process early. Beginning the process later would not allow sufficient time for these three applications to be prepared in series by the Companies' specialized team and submitted to NRC to meet the timely renewal deadlines.

The Oconee Nuclear Station was selected as the first plant to apply for SLR, even though the Robinson Nuclear Plant nuclear unit license expires earlier, because Oconee is the largest nuclear facility (approximately 2,600 MW (winter)) in DEC's nuclear fleet.

ORS Recommendation #12:

ORS recommends that Duke Energy Carolinas, LLC ("DEC") provide the status of its plans to relicense the Bad Creek Pumped Hydro units, including any actions it will have to take as part of the relicensing process and any costs that it will incur to relicense the units. ORS recommends this information be provided in a modified IRP in this proceeding.

Response:

DEC intends to obtain a new Federal Energy Regulatory Commission ("FERC") License for the Bad Creek Hydroelectric Station, whose current license expires on July 31, 2027. The Federal Power Act requires nonfederal hydroelectric projects to relicense after the original license expires, with the new license being granted for 30-50 years.

Per FERC regulations, DEC will file the Notice of Intent ("NOI") and Pre-Application Document ("PAD") in Q1 2022 with the expectation of filing an Application for New License in Q4 2025. DEC intends to utilize FERC's Integrated Licensing Process ("ILP") which allows input from a stakeholder team that brings together state, federal, and local agencies and non-governmental organizations, as well as interested citizens, to participate in the development of protection, mitigation and enhancement measures for the Project.

The PAD is a requirement of FERC regulations issued in the year 2003 (218 CFR Part 5) and must be filed with the NOI to file an Application for New License. According to the regulations, the documents must be filed at least five years, but not more than five and one-half years, before the expiration of the existing license. The purpose of the PAD is to provide detailed information about a project at the beginning of the relicensing process to help focus participants on key issues. The ILP requirements are designed to allow the PAD to evolve into a final license application. Specific information that must be included in the PAD includes:

- A description of the project's facilities and operation;
- A description of the existing environment and any known and potential project effects on specific resources including: geology and soils; water resources; fish and aquatic resources; wildlife and botanical resources; wetlands, riparian, and littoral habitats; rare, threatened, and endangered species; recreation and land use; aesthetic resources; cultural resources; socioeconomic resources; tribal resources; and a description of the river basin;
- A list of preliminary issues and studies that may be needed at the project;
- An appendix summarizing contacts with stakeholders sufficient to enable the Commission to determine if due diligence has been exercised in obtaining relevant information;

- A process plan and schedule for consulting stakeholders, gathering information, developing and conducting studies, obtaining permits and completing all pre-filing licensing activities; and

- If applicable, a statement of whether or not the applicant will seek benefits under section 210 of the Public Utility Regulatory Policies Act of 1978.

The final step is to file the relicensing application for the Bad Creek units in Q4 2025 with the expectation to receive the final FERC license in Q3 2027. DEC expects operation under the new FERC license to commence as of August 1, 2027.

DEC has not yet made any cost estimations regarding the relicensing process. However, DEC has a Hydro Strategy & Licensing group of 10 full-time employees dedicated to managing the regulatory processes of all twenty-seven (27) hydroelectric stations in the Carolinas representing over 3,500 MW of carbon-free generating capacity.

DEC commits to including a status update on the Bad Creek relicensing in future IRPs. In addition to including Bad Creek Relicensing in the DEC 2021 Update IRP to be filed in September 2021, DEC intends to file the NOI and PAD for Bad Creek units in Q1 2022.

ORS Recommendation #16:

ORS recommends the Companies provide additional justification for the combustion turbine ("CT") capital cost assumption. ORS recommends this information be provided in a modified IRP in this proceeding.

Response:

The Companies typically build multiple CTs at a greenfield installation to realize economies of scale associated with land, roads, buildings and other common infrastructure. All DEC and DEP combustion turbines are located at multi-unit sites.[1] Consistent with this practice, the Companies' CT capital cost assumptions used in development of the IRP are based on consultant estimates that reflect the average cost to construct 4 x F-Class CTs at a greenfield installation. The consultant provides estimates for the cost of the "first unit" and the "next unit" for a greenfield site. The first unit cost includes the infrastructure cost previously mentioned and the first unit cost is significantly greater than the cost to construct the next unit at the site. The Companies' CT cost thus reflects the average cost to build one "first unit" and three "next units" based on the consultant estimates.

The Companies researched the data sources for the CT costs included in Table 14 of Exhibits AMS-1 and AMS-2 and note the following:

- EIA develops capital cost and performance characteristics for utility scale generating technologies for use in EIA's Annual Energy Outlook. The EIA data used in Table 14 is based on the EIA publication "Cost and Performance Characteristics of New Generating Technologies," Annual Energy Outlook, February 2021. Importantly, the EIA data reflects the cost to build a single F-class CT at a greenfield installation and thus does not reflect the economies of scale associated with building multiple units at a site and spreading infrastructure costs among multiple units.[2] Although a small utility may only plan for a single 240-MW gas turbine site, this planning assumption is not relevant to larger utilities such as the Companies and therefore results in a cost substantially higher than the Companies' expected cost.

- The NREL data is based on the 2020 EIA Annual Energy Outlook. Note however, that the NREL CT cost reflects the average of the advanced and conventional systems as reported by EIA and assumes a plant size of 171 MW.[3] The advanced CT is based on an F-class CT with a unit rating of approximately 240 MW and the conventional CT is based on 2 x LM6000 aeroderivative CTs with a net output of approximately 100 MW. Aeroderivative CTs have a much higher cost on a $/kW basis compared to an F-class CT, and the aeroderivative CT is not the type of CT that the Companies would build strictly for peaking purposes. Based on the 2020 EIA data, the capital cost of the aeroderivative CT is

[1] *See* 2020 DEC and DEP IRPs, Appendix B.
[2] U.S. Energy Information Administration, Annual Energy Outlook 2021 (Feb. 2021), *available at* https://www.eia.gov/outlooks/aeo/assumptions/.
[3] Nat'l Renewable Energy Laboratory, Other Technologies (EIA), https://atb.nrel.gov/electricity/2020/index .php?t=ei (last visited Mar. 18, 2021).

approximately 65% greater than the single F-class CT.[4] Thus, the NREL CT cost data does not provide a valid comparison to Duke's F-class CT.

- The Lazard data provides low and high CT capital cost estimates. The cost of a gas turbine for Lazard is again based on a single unit site, with the low case based on a single 240 MW plant while the high case is based on a single 50 MW plant. Again, for a large utility such as Duke a multi-unit site would be utilized with Duke's expected site to contain 4 units, leading to substantial economies of scale savings. Page 18 of the Lazard report contains the assumptions for the gas peaking option.[5]

- The NRC data is also based on the EIA AEO data for their reference natural gas plant and thus also reflects the cost to build a single F-class CT at a greenfield site and does not reflect the economies of scale associated with building multiple CTs at a greenfield site.[6]

- Kentucky Power Company and Southwestern Electric Power Company (both AEP Companies) use CT cost data developed by the AEP Engineering Services organization.[7] The CT data used by these companies reflects the cost to construct 2 x F-class CTs and includes a Selective Catalytic Reduction ("SCR") environmental installation for NOx control.[8] It should be noted that the SCR adds significant cost to the project. In the Carolinas, NOx limits can be achieved for an F-class CT through combustion control and would not require an SCR. Thus, cost data for the two AEP companies is inflated compared to the Duke estimates since the AEP data only reflects economies of scale for a 2 unit site (versus 4 unit site for the Duke Companies) and includes an SCR installation which would not be required in the Carolinas.

- The Dominion Energy South Carolina cost estimate is based on 2 x J-class CTs which is a larger CT than the F-class CT included in the Duke IRPs. The Dominion Energy South Carolina CT estimate is lower than the Duke estimate and the Dominion Energy Virginia CT estimate is in-line with the Duke estimate although it is not clear what type of CT is used as the basis for the Dominion Energy Virginia estimate.

A more appropriate comparison of the Companies' CT capital cost is to compare the first unit cost to the single unit CT costs from the other data sources. The Companies' first unit cost, which reflects the cost to build the first CT at a greenfield site including infrastructure, is [redacted]. It is notable that the first unit estimate is approximately 9% greater than the [redacted] EIA estimate to build a single unit at a greenfield site, which provides a more appropriate comparison of data

[4] U.S. Energy Information Admin., Capital Costs and Performance Characteristics for Utility Scale Power Generating Technologies, at 73, 77 (Feb. 2020), *available at* https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.
[5] Lazard, Lazard's Levelized Cost of Energy Analysis—Version 13.0, at 18, available at https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.
[6] U.S. Nuclear Reg. Comm'n, Replacement Energy Cost Estimates for Nuclear Power Plants: 2020-2030, Draft Report for Comment, at 36 (Dec. 2020), *available at* https://www.nrc.gov/docs/ML2034/ML20342A132.pdf.
[7] Southwestern Electric Power Company, Integrated Resource Planning Report to the Arkansas Public Service Commission, at 97 (Dec. 14, 2018), *available at* http://www.apscservices.info/pdf/07/07-011-U_32_2.pdf.
[8] *Id.* at 150.
[9] Reference the Companies' Generic Unit Summary provided in response to ORS AIR 2-2(d).

sources. In fact, the Companies' first unit cost is greater than or in-line with all of the Table 14 data sources except for the NREL data which is not a valid comparison as noted above.

Table 14
Generic Resource Comparison

Combustion Turbine											
	DEC & DEP	DESC	NREL (Low)	NREL (High)	Virginia Power	Kentucky Power	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NRC
Capacity (MW)	[redacted]										
Book Life (yrs)											
Capital Cost ($/kW)											
Fixed O&M ($/kW-yr)											
Variable O&M ($/MWh)											
Average Heat Rate (MBTU/MWh)											
Capacity Factor (%)											
LCOE											

In summary, the majority of the data sources reflect the cost to build a single CT at a greenfield installation and thus do not reflect the economies of scale associated with constructing 4 units at a site which is reflected in the Companies' estimate. The apples to apples comparison of the EIA single unit estimate closely tracks with the first unit cost of the Duke estimate. It is also notable that the Companies have multiple brownfield sites with potential future use for baseload and peaking installations that may further reduce the cost of future additions compared to the assumptions used in the IRP. The Companies believe that the CT cost used in development of its IRPs provides a reasonable estimate for the cost of future peaking capacity and the use of higher CT estimate would result in the non-optimal selection of resources in the IRP resulting in higher costs to consumers.

ORS Recommendation #9:

ORS recommends the Company provide tables summarizing the capital and operations and maintenance ("O&M") costs for compliance with environmental regulations by unit and by environmental regulation, and include descriptions explaining those costs. ORS recommends this information be included in a modified IRP in this proceeding.

Response:

The Companies have provided the costs that can be avoided by retiring coal units with respect to compliance with federal and environmental regulations. These costs are broken down by unit, by year, and by environmental regulation and include capital, fixed O&M, and variable O&M. As mentioned in the ORS Report, the Companies are including these costs in the PVRR analysis appropriately. While this information is helpful to understand the costs specifically to comply with environmental regulations, this information is not well suited for inclusion in the IRP, but may be better supplied as data requests in future IRP dockets.

Costs identified in Tables 1-7 below reflect the costs in the Base Case without Carbon Policy. This is the case with the highest utilization of the coal units, and reflects the scenario with the highest compliance costs, as coal units run more and for longer in this portfolio compared to the other portfolios.

Avoidable costs associated with air regulations (SO2, NOx, and Hg), are captured in the North American Air Quality Standards tables. Those costs that are avoidable with respect to water regulations are captured in the 316(b) tables. These costs reflected currently planned costs to comply with 316(b) standards, though, as mentioned in the Companies' Response to ORS AIRs 2-19, the U.S. Environmental Protection Agency has not yet ruled on any of these plans as of yet. Costs that represent compliance with waste by-products are captured in the Steam Electric Effluent Limitation Guidelines tables. As noted in the description below, the DEP Coal units sell combustion by-product which overall reduces their costs to the system.

Recommendation 9 Table 1

NAAQS		Compliance Cost ($)														
Unit	Cost Descption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1		[redacted]														
Allen 2																
Allen 3																
Allen 4																
Allen 5																
Belews Creek 1																
Belews Creek 2																
Cliifside 5																
Cliifside 6																
Marshall 1																
Marshall 2																
Marshall 3																
Marshall 4																
Mayo 1																
Roxboro 1	SCR Damper Replacement															
Roxboro 2																
Roxboro 3																
Roxboro 4																

Recommendation 9 Table 2

NAAQS		Compliance Cost ($/MWh)														
Unit	Cost Descption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1	Reagents	[redacted]														
Allen 2	Reagents															
Allen 3	Reagents															
Allen 4	Reagents															
Allen 5	Reagents															
Belews Creek 1	Reagents															
Belews Creek 2	Reagents															
Cliifside 5	Reagents															
Cliifside 6	Reagents															
Marshall 1	Reagents															
Marshall 2	Reagents															
Marshall 3	Reagents															
Marshall 4	Reagents															
Mayo 1	Reagents															
Roxboro 1	Reagents															
Roxboro 2	Reagents															
Roxboro 3	Reagents															
Roxboro 4	Reagents															

Recommendation 9 Table 3

316(b)		Compliance Cost ($)														
Unit	Cost Descption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1		[redacted]														
Allen 2																
Allen 3	316(b) Implementation															
Allen 4	316(b) Implementation															
Allen 5	316(b) Implementation															
Belews Creek 1	316(b) Implementation															
Belews Creek 2	316(b) Implementation															
Cliifside 5																
Cliifside 6																
Marshall 1	316(b) Implementation															
Marshall 2	316(b) Implementation															
Marshall 3	316(b) Implementation															
Marshall 4	316(b) Implementation															
Mayo 1																
Roxboro 1	316(b) Implementation															
Roxboro 2	316(b) Implementation															
Roxboro 3	316(b) Implementation															
Roxboro 4																

Recommendation 9 Table 4

316(b)		Compliance Cost ($)														
Unit	Cost Descption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1		[redacted]														
Allen 2																
Allen 3	316(b) Implementation															
Allen 4	316(b) Implementation															
Allen 5	316(b) Implementation															
Belews Creek 1	316(b) Implementation															
Belews Creek 2	316(b) Implementation															
Cliifside 5																
Cliifside 6																
Marshall 1	316(b) Implementation															
Marshall 2	316(b) Implementation															
Marshall 3	316(b) Implementation															
Marshall 4	316(b) Implementation															
Mayo 1																
Roxboro 1	316(b) Implementation															
Roxboro 2	316(b) Implementation															
Roxboro 3	316(b) Implementation															
Roxboro 4																

Recommendation 9 Table 5

ELG		Compliance Cost ($)														
Unit	Cost Descption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1		[redacted]														
Allen 2																
Allen 3																
Allen 4																
Allen 5																
Belews Creek 1	VSEP															
Belews Creek 2	VSEP															
Cliifside 5	Station Wastewater Treatment, VSEP															
Cliifside 6																
Marshall 1	VSEP															
Marshall 2	VSEP															
Marshall 3	VSEP															
Marshall 4	VSEP															
Mayo 1																
Roxboro 1	VSEP															
Roxboro 2	VSEP															
Roxboro 3	VSEP															
Roxboro 4	VSEP															

Recommendation 9 Table 6

ELG		Compliance Cost ($)														
Unit	Cost Descption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1		[redacted]														
Allen 2																
Allen 3																
Allen 4																
Allen 5																
Belews Creek 1	VSEP															
Belews Creek 2	VSEP															
Cliifside 5	Station Wastewater Treatment, VSEP															
Cliifside 6																
Marshall 1	VSEP															
Marshall 2	VSEP															
Marshall 3	VSEP															
Marshall 4	VSEP															
Mayo 1																
Roxboro 1	VSEP															
Roxboro 2	VSEP															
Roxboro 3	VSEP															
Roxboro 4	VSEP															

Recommendation 9 Table 7

ELG		Compliance Cost ($/MWh)														
Unit	Cost Descption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allen 1	Waste	[redacted]														
Allen 2	Waste	[redacted]														
Allen 3	Waste	[redacted]														
Allen 4	Waste	[redacted]														
Allen 5	Waste	[redacted]														
Belews Creek 1	Waste	[redacted]														
Belews Creek 2	Waste	[redacted]														
Cliifside 5	Waste	[redacted]														
Cliifside 6	Waste	[redacted]														
Marshall 1	Waste	[redacted]														
Marshall 2	Waste	[redacted]														
Marshall 3	Waste	[redacted]														
Marshall 4	Waste	[redacted]														
Mayo 1	Waste (Net Sale and Disposal)	[redacted]														
Roxboro 1	Waste (Net Sale and Disposal)	[redacted]														
Roxboro 2	Waste (Net Sale and Disposal)	[redacted]														
Roxboro 3	Waste (Net Sale and Disposal)	[redacted]														
Roxboro 4	Waste (Net Sale and Disposal)	[redacted]														

ORS Recommendation #5:

ORS recommends the Companies provide additional justification for selecting the Base energy efficiency ("EE") and demand-side management ("DSM") case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. ORS recommends this information be included in a modified IRP in this proceeding.

Response:

The Companies selected the base EE and base DSM cases for inclusion in the Base Case Portfolios for several reasons. While sensitivity analysis does show that additional EE and DSM savings may be a cost effective solution, the uncertainty associated with these higher projections was substantial. The Companies viewed the most prudent approach was to set the foundation of the base cases with known and verifiable measures and adoption rates based on historical performance of their EE and DSM programs, which have garnered praise from environmental advocates as the leading utility energy efficiency programs in the Southeastern United States. The High EE forecast becomes increasingly uncertain as it projects and quantifies unspecified potential new measures, impacts of new or enhanced customer programs, and combined effects of the High Avoided Energy Cost scenario and the Enhanced scenario from the market potential study, accounting for higher avoided energy cost benefits and additional customer incentives for adoption.

The High DSM forecast also has significant uncertainty. This forecast is predicated on the implementation of customer Time of Use rates and other rate-enabled programs to incentivize changes to customer load profiles at times of peak energy demand. The cost effectiveness and reliable potential are yet to be demonstrated in the Companies' service territories, and therefore, speculative at this point in time. At the time of inclusion of this forecast in the IRP, the Tierra Resource Consults, LLC and Dunsky Energy Consulting Winter Peak Study was still on-going. While it is possible these programs could demonstrate additional cost savings, the uncertainty associated with the forecast, including regulatory approval, timing of implementation and magnitude of impact, were the driver for relying on the base forecasts in development of base case portfolios. Additionally, if the potential rate-enabled customer programs identified in the Winter Peak Study prove to be viable in the Companies' service territory, these impacts on customer load shapes and peak demand will generally be reflected in the load forecast, not as a traditional dispatchable DSM program.

As discussed in the IRP, the sensitivity analysis informed the development of the alternate portfolios. The higher EE and DSM forecasts were utilized in Portfolio D, E, and F, where carbon reduction was optimized, and the capital cost for replacement capacity resources was higher, incorporating higher cost resources to drive the emissions reductions. The additional EE and DSM would have compounding benefits in these portfolios and would contribute to the policy discussions around the necessity of EE and DSM to continue to reduce costs in resource restricted or carbon emissions driven portfolios.

ORS Recommendation #21:

ORS recommends the Companies include post in-service capital costs for new resource additions in their capital cost model and Present Value of Revenue Requirement ("PVRR") calculations for each Portfolio and each sensitivity of each Portfolio. ORS recommends this be addressed in a modified IRP in this proceeding.

Response:

Post in-service capital costs for all new resource additions were included as appropoiate in both the PVRR and the customer bill impact analysis. While the post in-service capital costs for batteries are captured separately in the PVRR analysis, in the Capital Cost workbooks, the post in-service capital costs for all other resources are captured in the production cost of the model. The Generic Unit Summary, which was provided in the Companies' Response to ORS Data Request 2-2(d), identifies the Levelized Capital Maintenance costs of new resources, such as the new CTs, CCs, solar, wind, and nuclear small modular reactors ("SMRs") in the IRP. These costs were included in the variable O&M, operating charges, and start costs in the production cost model. These costs are reflected in the modeling results files, provided in the Companies' Response to ORS Data Request 2-10(e), and are included in the PVRR and Bill Impact Analysis via the Production Costs by Company files provided in the Companies' Response to ORS Data Resquest 2-10(c).

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

To the extent information differs for DEC and DEP, provide the different information, otherwise please note the information provided is the same for both.

Request:

2-2 Refer to 2020 IRP_Model_Inputs_CONFIDENTIAL Excel workbook.

d. Refer to the New Unit Cost tab. Provide all workpapers used to derive these values and include all assumptions. Please identify and describe the source of the book lives used for each of the new resources. Provide a copy of the source information relied on for all information associated with the New Unit data, such as the book lives.

Response:

d. Please see attached confidential file for all supporting information for the New Unit Cost tab, including information on book lives.

SCORS2-2
Confidential - IRP Gen

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Note – the information sought for the questions below continue to apply to both DEC and DEP, though specific page numbers refer to DEC. Again, to the extent information differs for DEC and DEP, provide the different information, otherwise note the information provided is the same for both.

Note – the Request was revised by ORS on November 10, 2020, pursuant to communications between ORS and the Companies. The update request and corresponding response is provided below:

Revised Request:

2-10 See page 94, which states, "The results of these hourly production cost model runs were paired with the accompanying capital costs…" and the results are presented in Table 12-A.

(c) For each of the 54 cases, provide the economic analyses, electronically, that took the production cost results and paired them with capital cost results to derive the ultimate PVRR results. Please ensure there are no pasted values and all referenced spreadsheets are supplied.

(e) For two of the 54 cases, specifically the Base Case with and without CO2, provide the PROSYM input data bases and the annual PROSYM output reports.

Response:

Please note due to the size and volume of documents being referenced throughout this response, the documents are not attached hereto but instead are being directly uploaded to the FTP site and housed in a folder labeled "ORS AIR 2-10 (Responsive documents – CONFIDENTIAL)."

c. Please see the following attachments for the economic analysis of each of the 54 cases:

- 2020 ORS DR 2, 2-10C-1A (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1A (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1B (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1B (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1C (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1C (DEP) CONFIDENTIAL.xlsx

- 2020 ORS DR 2, 2-10C-1D (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1D (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1E (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1E (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1F (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-1F (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-2 CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3A (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3A (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3B (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3B (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3C (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3C (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3D (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3D (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3E (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3E (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3F (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3F (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3G (DEC) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-3G (DEP) CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-4A CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-4B CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-4C CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-4D CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-4E CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10C-4F CONFIDENTIAL.xlsx

e. Input data bases for Base CO2 and Base No CO2 have been provided as attachment 2-10 in sub folders “2007281522 (Base No CO2)” and “2007271551 (Base CO2)”

No monthly output reports were created for the IRP. Please refer to the following attachments for all Annual Prosym Outputs used in the IRP:

- 2020 ORS DR 2, 2-10E-1A CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1B CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1C CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1D CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1E CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1F CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1G CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1H CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-1I CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2A CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2B CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2C CONFIDENTIAL.xlsx

- 2020 ORS DR 2, 2-10E-2D CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2E CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2F CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2G CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2H CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-2I CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3A CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3B CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3C CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3D CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3E CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3F CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3G CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3H CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-3I CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4A CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4B CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4C CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4D CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4E CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4F CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4G CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4H CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-4I CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5A CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5B CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5C CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5D CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5E CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5F CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5G CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5H CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-5I CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6A CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6B CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6C CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6D CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6E CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6F CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6G CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6H CONFIDENTIAL.xlsx
- 2020 ORS DR 2, 2-10E-6I CONFIDENTIAL.xlsx

ORS Recommendation #23:

ORS recommends the Companies revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the Present Value of Revenue Requirement ("PVRR"), except for the levelization of the capital-related costs. ORS recommends this be included in a modified IRP in this proceeding.

Response:

The differences the ORS highlights reflect the differences between average total capital-debt structure, and cost of capital and debt of the utility, used in the customer bill impact analysis compared to incremental costs which are based on future projected capital-debt structure, and cost of capital and debt of the utility used in the PVRR analysis. The Companies' believe that the difference for the two separate analyses are appropriate for the assumptions used in each of the analyses.

ORS suggests that the Companies should use the same capital structure and cost of capital in the Customer Bill Impact Analysis as was used in the PVRR analysis. The capital structure and cost of capital in the PVRR analysis reflects a generic future capital structure and cost of capital for new future resources. The capital structure and cost of capital in the Customer Bill Impact Analysis represents the most recent capital structure and costs of capital authorized by the Commission and the NCUC, which is appropriate when calculating customer bill impacts as these cost of capital and capital structures are meant to represent a composite cost of capital and capital structure for all assets being passed on to customers. As noted in the analysis, the Companies did not try to project future changes to Customer Bill Impact Analyses, with the additions of new resources, and cost of service allocations.

ORS suggests that the Companies should use the same depreciation expense in the Customer Bill Impact Analysis as was used in the PVRR analysis. While the Companies agree that the current depreciation rates reflect the remaining net book value and salvage value over the remaining lives of its existing resources, the rate should reflect the aggregate of the existing and future resources, which is closer to the existing depreciation rates. This is why the Companies chose to use the existing depreciation rates in the Customer Bill Impact Analysis.

ORS suggests that the Companies should use the same income tax rates between the Customer Bill Impact analysis and the PVRR analysis. The Companies believe it is appropriate that these numbers are different because the income tax rate in the PVRR analysis reflects the tax rates over the life of the new resources, whereas the income tax rate of the Customer Bill Impact Analysis should represent a weighted average income tax rate of existing and future resources that more closely mirrors the current income tax rate assumed for the Customer Bill Impact Analysis.

In short, ORS's recommendation underscores the different assumptions used in the PVRR and Customer Rate Impact Analyses. The Companies intend to work collaboratively with ORS on refining and fine-tuning these analyses.

ORS Recommendation DEC #24:

ORS recommends DEC provide additional details and status updates about resources included in the action plan, including coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. ORS recommends this information be included in a modified IRP in this proceeding.

ORS Recommendation DEP #24:

ORS recommends the Company provide additional details and status updates about resources included in the action plan, including CT retirements, unnamed energy storage projects, and the nuclear uprates. ORS recommends this information be included in a modified IRP in this proceeding.

Response:

Included in the Tables below are additional details and status updates about resources included in the Companies' Short Term Action Plans ("STAP") including coal and CT retirements, the Lincoln CT project, unnamed energy storage and combined heat and power ("CHP") projects, nuclear uprates, and Bad Creek upgrades.

2020 Duke Energy Carolinas Short-Term Action Plan [11] [12]

Base Case with Carbon Policy

Year	Retirements [1]	Designated Additions [2]	Renewable Resources (Cumulative Nameplate MW): Solar [3]	Solar w/ Storage [4]	Biomass/ Hydro [5]	Undesignated Additions [6]	Cumulative EE [7]	DSM [8]	IVVC [9]	Relicensing Activities [10]
2021	270 MW Allen 3	6 MW Nuclear Uprate 65 MW Bad Creek Upgrade 16 MW Clemson CHP	966	0	132	9 MW Energy Storage	70	478	0	Oconee SLR Application expected to be filed
2022	434 MW Allen 2 and 4	21 MW Nuclear Uprates 65 MW Bad Creek Upgrade	1,327	115 w/ 25 Storage	118	20 MW Energy Storage 30 MW CHP	129	467	0	Bad Creek NOI and PAD expected to be filed in Q1
2023		30 MW Nuclear Uprates 65 MW Bad Creek Upgrade	1,673	134 w/ 30 Storage	81	25 MW Energy Storage 30 MW CHP	183	468	17	N/A
2024	426 MW Allen 1 and 5	65 MW Bad Creek Upgrade	1,976	163 w/ 35 Storage	81	25 MW Energy Storage	233	470	34	N/A
2025		402 MW Lincoln CT Project	2,268	192 w/ 45 Storage	59	26 MW Energy Storage	303	473	173	Bad Creek Application for New License expected to be filed in Q4

Notes:

- Detailed information associated with column numbers in following table.
- Capacities shown in winter ratings unless otherwise noted.
- Dates represent the year the project impacts winter peak.

DEC Short Term Action Plan Information	
Column	Notes
1 - Retirements	Retirement dates reflect 'most economical' dates from the IRP Coal Retirement Analysis unless otherwise noted.
	Allen 3 was projected to retire on 12/2021 in the 2020 IRP. Retirement date has been revised to 3/31/2021. Letter of intent was filed with PSCSC and NCUC on 2/2/21. This is a change from filed IRP.
2 - Designated Additions	These are additions that are currently underway, approved or signed. These are included in the first need calculation.
	Nuclear uprates are currently underway. The following uprates are planned: Oconee 1 MUR; 15 MW in Jan 2023 Oconee 2 MUR; 15 MW in Jan 2022 Oconee 3 MUR; 15 MW in May 2022 Catawba 1 LP Turbine; 6 MW in May 2020 Catawba 2 LP Turbine; 6 MW in Apr 2021
	Bad Creek uprates are currently underway. The following uprates are planned: Bad Creek 1; 65 MW in Sept 2021 (underway) Bad Creek 2; 65 MW in Sept 2020 (complete) Bad Creek 3; 65 MW in Sept 2022 Bad Creek 4; 65 MW in Sept 2023
	Clemson Combined Heat and Power; 15 MW; online Nov 2020.
	Lincoln CT project; 402 MW in Dec 2024; agreement with Siemens to install an HL-class CT at the Lincoln site. Extended commissioning began in 2020. Testing is currently underway. The Company will take care, custody, and control of the completed 402 MW unit in 2024. The CPCN for the Lincoln project was approved by the NCUC on December 7, 2017 in Docket E-7, Sub 1134.
3 - Solar	Capacity is shown in nameplate ratings and does not include solar coupled with energy storage. Includes designated, mandated and undesignated solar projects.
4 - Solar with Storage	Solar coupled with storage; storage only charged from solar facility and not the grid. Includes designated, mandated and undesignated solar with storage projects.
5 - Biomass/Hydro	Non-solar renewable assets currently under contract. Includes landfill gas, poultry waste and hydro.
6 - Undesignated Additions	These are additions that are not currently underway, approved or signed. These are not included in the first need calculation.
	Energy storage is a placeholder for grid-tied storage and represents total usable MW.
	CHP represents placeholders for two projects currently being negotiated but not yet signed. Project names will not be released until an agreement has been signed.
7 - Cumulative EE	Cumulative energy efficiency programs expected in DEC. For a detailed explanation of the projects included in this line item, refer to Appendix D in the DEC IRP.
8 - DSM	Demand response activations expected in DEC. For a detailed explanation of the projects included in this line item, refer to Appendix D of the DEC IRP.
9 - IVVC	Expected IVVC impact of the top 10% of peak hours. IVVC is part of the proposed Duke Energy Carolinas Grid Improvement Plan (GIP) expected to be approved by 2022, the IVVC program is expected to be fully implemented in DEC by 2025. For a detailed discussion of IVVC refer to Appendix D. (Remainder of IVVC impacts included in the load forecast)
10 – Relicensing Activities	Information on relicensing activities underway for DEC assets.

Notes 11 & 12: General Table	Capacities shown in winter ratings unless otherwise noted.
	Dates represent the year the project impacts winter peak.

2020 Duke Energy Progress Short-Term Action Plan (10) (11)
Base Case with Carbon Policy

			Renewable Resources (Cumulative Nameplate MW)						
Year	Retirements (1)	Designated Additions (2)	Solar (3)	Solar w/ Storage (4)	Biomass/ Hydro (5)	Undesignated Additions (6)	Cumulative EE (7)	DSM (8)	IVVC (9)
2021	514 MW Darlington CT 1-4, 6-8, 10	560 MW Asheville CC	2,888	0	284	30 MW Energy Storage	43	507	0
2022			3,144	0	146	15 MW Energy Storage	78	517	0
2023			3,430	0	135	18 MW Energy Storage	111	521	9
2024			3,641	14 w/ 3 Storage	131	18 MW Energy Storage	141	519	19
2025		4 MW Nuclear Uprate	3,850	13 w/ 3 Storage	131	20 MW Energy Storage	185	329	96

- Detailed information associated with column numbers in following table.
- Capacities shown in winter ratings unless otherwise noted.
- Dates represent the year the project impacts winter peak.

DEP Short Term Action Plan Information	
Column	Notes
1 - Retirements	Retirement dates reflect 'most economical' dates from the IRP Coal Retirement Analysis unless otherwise noted.
2 - Designated Additions	These are additions that are currently underway, approved or signed. These are included in the first need calculation.
	Nuclear uprates are currently underway. The following uprates are planned: Brunswick 1 feedwater heater; 4 MW in May 2024
	Asheville Combined Cycle; 560 MW was installed in December 2020. (impacts winter peak of 2021)
3 - Solar	Capacity is shown in nameplate ratings and does not include solar coupled with energy storage. Includes designated, mandated and undesignated solar projects.
4 - Solar with Storage	Solar coupled with storage; storage only charged from solar facility and not the grid. Includes designated, mandated and undesignated solar with storage projects.
5 - Biomass/Hydro	Non-solar renewable assets currently under contract. Includes landfill gas, poultry waste and hydro and.
6 - Undesignated Additions	These are additions that are not currently underway, approved or signed. These are not included in the first need calculation.
	Energy storage is a placeholder for grid-tied storage and represents total usable MW.
7 - Cumulative EE	Cumulative energy efficiency programs expected in DEP. For a detailed explanation of the projects included in this line item, refer to Appendix D in the DEP IRP.
8 - DSM	Demand response capability expected in DEP. For a detailed explanation of the projects included in this line item, refer to Appendix D of the DEP IRP. DSM declines as IVVC ramps up. IVVC replaces existing DSDR program.
9 - IVVC	Expected IVVC impact of the top 10% of peak hours. IVVC is part of the proposed Duke Energy Carolinas Grid Improvement Plan (GIP) expected to be approved by 2022, the IVVC program is expected to be fully implemented in DEP by 2025. IVVC will replace current DSDR program (included in DSM). As IVVC comes online, DSM is reduced. For a detailed discussion of IVVC refer to Appendix D. (Remainder of IVVC impacts included in the load forecast)
10 – Relicensing Activities	No activities at this time.
Notes 11 & 12: General Table	Capacities shown in winter ratings unless otherwise noted.
	Dates represent the year the project impacts winter peak.

ORS Recommendation #13 (DEP Only):

ORS recommends Duke Energy Progress, LLC ("DEP") provide additional clarification regarding its plans for the retirement of the Darlington CT units, including details about any transmission impacts. ORS recommends this information be provided in a modified IRP in this proceeding.

Response:

Darlington CTs 1-4, 6-8, and 10 were retired on March 31, 2020, five months before the filing of the IRP. These particular Darlington units had reached the end of their depreciable lives per the most recently approved depreciation study as part of the DEP rate case. In the past, the Darlington CT site provided transmission support to the DEP Robinson Nuclear Station. Robinson Nuclear Station installed automatic load tap changing transformers in the fall of 2018 in anticipation of the retirement of the older CT units at the Darlington site, alleviating the need for transmission support provided by the Darlignton site.

The units underwent the formal retirement process as described in Snider Rebuttal Exhibit 17. As noted on page 212 in the 2020 DEP IRP, the Darlington units listed above were included in 2020 winter capacity planning reserve margin. The units were also included in the Short Term Action Plan in the IRP to note that they were included in the previous year and are no longer included in the 2021 winter capacity planning reserve margin.

Darlington CT11 was retired on November 8, 2015; CT 9 was retired on June 30, 2017; and CT 5 was retired on May 31, 2018. CTs 12 and 13 are still operational units at the Darlington site.

ORS Recommendation #15:

ORS recommends the Companies supply additional information explaining the basis for how combined heat and power ("CHP") resources were added to the Short-Term Action Plan ("STAP"), and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. ORS recommends this information be provided in a modified IRP in this proceeding.

Response:

CHP projects are included in the STAP because they are near-term initiatives and programmatic approaches to providing customers with steam and, potentially, electricity. The projects included in the IRP and STAP are projects that are either in discussions or targeted for deployment. The inclusion of these resources in the STAP gives an indication to stakeholders and regulators that the Companies are continuing efforts to pursue solutions for a variety of customer needs including onside generation and steam production for industrial process, heating, cooling, or other needs. In the future, the Companies are willing to exclude uncommitted CHP projects from the STAP in future IRP filings, if that is the ORS's preference. These resources, it should be noted, are excluded from the First Year of Need calculation in the IRP because they are uncommitted resources.

CHP resources are not included in the economic optimization of the portfolio. These units are not eligible for economic selection because CHPs, by their nature, are customer-specific. The Companies will not build a CHP project without working extensively with the customer requiring the output of the unit (steam and potentially electricity). The Companies would also not seek out a project in a certain year in the future simply to fulfill a small amount of capacity need considering the lead time to procure a CHP project. The typical size of CHP projects of less than 25 MWs, and the magnitude of the system peak load in the Carolinas utilities.

ORS Recommendation #13:

ORS recommends Duke Energy Carolinas, LLC ("DEC") provide additional clarification regarding its plans for the retirement of the Allen units, including details about any transmission impacts, an explanation of the steps being pursued to receive final approval within DEC and from any regulatory body, and a timeline for conducting these activities. ORS recommends this information be provided in a modified IRP in this proceeding.

Response:

When retiring generating assets, the Companies follow a standardized process to make informed decisions with the best information available at that time, including, but not limited to, economic analysis, system reliability, and transmission implications. Prior to seeking formal internal approval for a plant retirement, the Companies conduct an internal stakeholder review soliciting input from various stakeholders throughout the orginization. Once that review is complete, the retirement is reviewed for management approval. Assets meeting certain thresholds are reviewed by the Companies' Transaction Review Committee before being sent to the CEO for approval. Once the Companies receive approval, the internal stakeholders are made aware of the approval, and station management works with station employees on transition plans while community representatives are notified. The Companies do not require regulatory approval to retire assests; however, the Companies do file letters with the Commission and the NCUC notifying these bodies of the generation assets retirement.

DEC recently completed this process for Allen Unit 3 and determined that (i) Allen Unit 3 should be closed as of March 31, 2021 and (ii) the unit retirement does not require replacement generation to maintain adequate planning reserves. The same process will be undertaken with units 2 and 4 later this year and with units 1 and 5 in 2023 as outlined in the Companies' Response to ORS DR 6-10.

The limiting factor for transmission support with respect to the retirement of Allen's generation are the two 230/100kV autobanks at the station. These banks, under certain contingencies, have the potential to overload. The existing 100kV generation at Allen can be used to help support these banks and limit exposure to the risk of the banks overloading. To address this, DEC is replacing the two autobanks at the station with significantly larger banks. The existing Allen switch yard cannot support the new banks and new breakers/switches needed, so DEC is also building the new Southpoint Switching Station.

Units 2, 3, and 4 may retire without impact to the transmission system since those units will not be required to support the existing autobanks while the new switch yard is being constructed. Units 1 and 5 are needed to help support the existing banks, if necessary. Once the new switchyard project has been completed, Allen 1 and 5 will be retired. The required projects are expected to be completed in time to support the most economic retirement dates outlined in the 2020 IRP.

These retirement dates and timelines are subject to any changes in circumstances where the unit(s) may be required to maintain system reliability, for example to plan for contingencies such as the loss of generating units for an extended period of time. These scenarios will be evaluated at the time of retirement to best meet the customers needs.

DEC will continue to update the Commission on near-term planned unit retirements as part of the Company's Short Term Action Plans in future IRPs and IRP Updates in order to keep the Commission informed regarding unit retirements and the Companies' plans to ensure system reliability is maintained and future capacity needs are met.

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

To the extent information differs for DEC and DEP, provide the different information, otherwise please note the information provided is the same for both.

Request:

6-10 Please provide any presentations made to Duke's senior managers or Board of Directors regarding the Company's plans for the accelerated retirement of the Allen Steam Station. Provide a complete list of approvals that will be needed in order to retire the plant, and a timeline for the Company's plans.

Response:

DEC and DEP object to this request on the grounds that it seeks, in part, information and documents protected by the attorney/client privilege and the attorney work-product doctrine. Without waiving this objection, please see attached non-privileged, confidential and responsive documents. This response includes a presentation that originally contained privileged information which has since become public once the IRPs were filed; accordingly, such designation has been struck.

Attached is "Confidential Carolinas_IRP_PrelimUpdate_20200803_Final (003)" that was presented to Duke's Senior Management on 8/03/20, which includes the Company's plans for the accelerated retirement of Allen Steam Station (Slide 7 & 19). Also attached is "Confidential 2020 09.24 Board - Update on Carolinas IRP presentation _FINAL" that was presented to Duke's Board of Directors on 9/24/20, which includes the Company's plans for the accelerated retirement of Allen Steam Station (Slide 17). The process for retiring Allen Station will have to get approval from Duke's Transaction Review Committee ("TRC") and CEO. For the 2021 retirement of Allen Units 2-4 we plan to present to the TRC and CEO in Q2 2021 to seek approval for the retirement. We plan to go to the TRC and CEO in 2023 for the retirement of Allen Unit 1 and Allen Unit 5 at year-end 2023. Please note the timing of the retirement of Allen Unit 1 and Allen Unit 5 is dependent on the completion of the South Point transmission switching station.

Confidential 2020 09.24 Board - Update

Confidential Carolinas_IRP_PrelimU

Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's First Set of Requests for Production of Documents and Interrogatories to Carolinas Clean Energy Business Association
(Substituted as party of record for South Carolina Solar Business Alliance)

Interrogatory:

1-21. With respect to SBA Witness Lucas' testimony on pages 109-110 addressing enactment of H. 4940 and the ongoing work of the legislative committee and advisory board that has until fall 2021 to study changes to the electricity sector in South Carolina, please explain what, if any, recommendations SBA or Witness Lucas believe the Public Service Commission should undertake in this proceeding prior to June 2021 relating to energy market reforms in South Carolina.

Response:

ANSWER: SCSBA has no recommendations at this time.